A comprehensive method to estimate power system stability constraint costs

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A COMPREHENSIVE METHOD TO ESTIMATE POWER SYSTEM STABILITY CONSTRAINT COSTS

Submitted by J.E. Hodgson, B.Eng.(Hons.)
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Summary

This thesis presents the development of a planning tool which estimates constraint costs resulting from the transiently secure operation of a power system. Provided with such information, a planning engineer is able to make more informed judgements about future reinforcements to a network.

A probabilistic economic power system model has been developed to reflect the diversities in generation availability and customer demand over a long period of operation. Fast time domain simulation techniques have been employed to give an assessment of transient stability over a broad range of operating conditions. An algorithm has also been devised to remedy stability problems when they occur. This uses information about generation stability characteristics and economic data to stabilise the system at a low cost.

To achieve this, it has been necessary to formulate a special direct stability method which is capable of identifying generation in a power system which is contributing to its instability. Unique to this method is its ability to provide useful information in cases of subsequent-swing transient instability.

Results are presented for a typical National Grid Company planning scenario on the UK power system. The conclusions of this work draw comparisons between the overall method described in this thesis and pre-existing less sophisticated techniques. Ideas for the implementation of some of the techniques in an on-line environment, and other areas for further work, are also presented.

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Contents

List of Figures

List of Tables

Abbreviations

ACS	Average Cold Spell (of demand)
AC	Alternating Current
ANN	Artificial Neural Network
AVR	Automatic Voltage Regulator
BD	Bad Damping
CAMEL	Constraint Analysis using Monte carlo Evaluation of Loading
CCT	Critical Clearing Time
CEGB	Central Electricity Generating Board
COA	Centre Of Angle
COI	Centre Of Inertia
CT	Clearing Time
CTP	Contingency Termination Point
DC	Direct Current
DI	DIvergence
DSA	Dynamic Security Assessment
EAC	Equal Area Criterion
EEAC	Extended Equal Area Criterion
EMS	Energy Management System
ESCORT	Economic and Security Costing Of Reinforcements to the Transmission System
FACT	Flexible AC Transmission
GOAL	Generator Ordering And Loading program
KE	Kinetic Energy
LOLP	Loss Of Load Probability
MOD	Mode Of Disturbance

MSC	Mechanically Switched Capacitor
NGC	National Grid Company plc
NGCC	National Grid Control Centre
OASIS	On-line Algorithms for System Instability Studies
PC	Personal Computer
PE	Potential Energy
PEBS	Potential Energy Boundary surface
PF	Power Factor
POP	Pool Offer Price
PPP	Pool Purchase Price
PSE	PowSim Engine
PS	Pole Slip
PSP	Pool Selling Price
PSS	Power System Stabiliser
PVM	Parallel Virtual Machine
REC	Regional Electricity Company
SCADA	Supervisory Control and Data Acquisition
SEP	Stable Equilibrium Point
SF	Scaling Factor
SHE	Scottish Hydro Electric
SMP	System Marginal Price
SP	Scottish Power
SVC	Static VAr Compensator
TEF	Transient Energy Function
TEM	Transient Energy Margin
TSS	Transmission Services Scheme
UMIS	Uplift Management Incentive Scheme
VLL	Value of Lost Load

Terms and Definitions

The set of terms defined below are used throughout the thesis.

generator or generating company	Company owning one or more power stations.
machine (set)	A single synchronous or induction machine.
(generating) unit	A single machine set and associated control equipment, possibly including AVR and governor.
(generating) group	A number of generating units located at the same site, i.e. within a power station.
(demand) period	A section of a year referred to in demand modelling. Periods need not be continuous. For instance, the months March and November may constitute a period because the demand profile for both months is similar.
run-up (time)	The time taken for a generation unit to come-on line.
availability	The probability that an item of plant will be available at a given time. Note that generation unit availability statistics do not take run-up times into consideration, i.e. a generation unit is available provided it may be brought on line after a stipulated run-up time.
planned or maintenance outage	Plant taken off-line for maintenance purposes.
forced or breakdown outage	Plant taken off-line due to unforeseen problems, including faults or urgent maintenance.

(spinning) reserve	On-line unloaded generation plant used to meet sudden increases in system load or outages of other generation plant.
contingency	A credible fault or change in the power system.
merit order	List of generation units in the system, ranked in order by pool offer price, cheapest first.
in merit	A generation unit scheduled to be used to meet system demand based on its pool offer price is *in merit.*
out of merit	A generation unit not needed to meet system demand based on its pool offer price is *out of merit.*
Uplift	Component of pool selling price which makes provision for forecasting errors, ancillary services and constrained running.

List of Symbols

t	Time
$\underline{x}$	Power system state vector
V	Voltage
I	Current
P	Active power
Q	Reactive power
S	Apparent power
R	Resistance
C	Capacitance
L	Inductance
B	Susceptance
X	Reactance
Y	Complex admittance
Z	Complex impedance
E	Machine internal voltage
T	Torque
P	Power
Θ	Angular displacement
ω	Angular velocity
α	Angular acceleration
δ	Rotor angle
θ	Rotor angle with respect to COA
G	Machine MVA rating
H	Machine inertia constant
M	Angular momentum
J	Inertia
R_C	Constraint rank
R_I	Rank for index I
ε_I	Rank error for composite index I
m	Number of generation groups
c	Number of contingencies
P_A	Probability of availability
r	Random number
$N - x$	Transmission security standard

Chapter One

Introduction

Since the first electric light bulb glowed into life, a little over a hundred and twenty years ago, the uses for electricity have grown massively. Enormous efforts have been made since to generate electricity in bulk and transport it efficiently to homes and factories where it may be converted to other forms of energy. The fruits of this labour are highly sophisticated generation, transmission and distribution systems capable of meeting the consumer's needs at a mere flick of a switch.

Such sophistication and convenience, however, comes at a cost. The complexity of the techniques and strategies required to control modern power systems is daunting. Inevitably, operational practices must reflect the time-constrained dynamic environment in which they are put to use. Safety factors are added to operational parameters, and these, in turn, incur unnecessary costs. These practices are mirrored during the planning of power systems, resulting in the commissioning of expensive transmission assets which are not fully utilised.

The primary aim of the work described in this thesis is to provide engineers with a tool that enables them to plan to meet tomorrow's demands while satisfactorily balancing operational costs with investment in the power system.

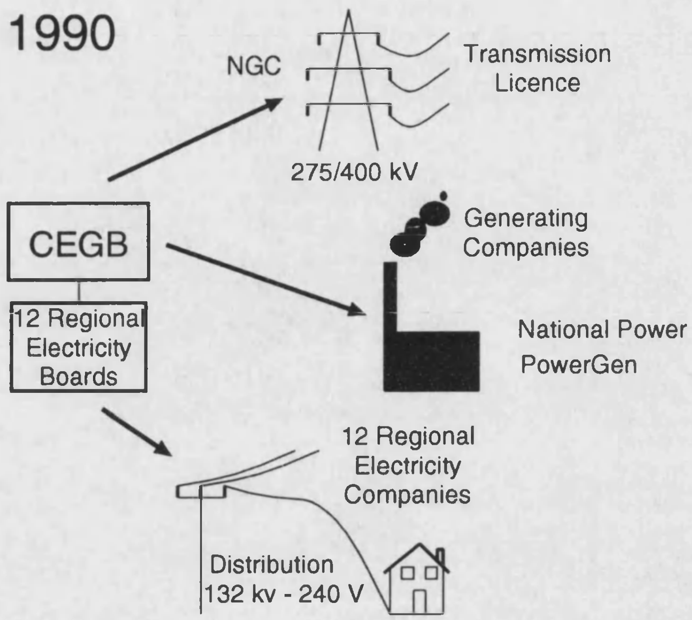


Figure 1.1: Privatisation of the UK electricity industry in 1990.

1.1 The UK power system

Prior to 1990, the power system in the UK was run by the Central Electricity Generating Board (CEGB), which was accountable for the supply of energy to 12 regional electricity boards. To better facilitate competition in generation and distribution, the electricity industry was privatised [3]. Several generation companies have since been founded, of which PowerGen and National Power are the largest. The regional electricity boards were made into regional electricity companies (RECs), responsible for the distribution of electricity to end users. Transmission became the responsibility of the National Grid Company plc (NGC). Distinction between transmission and distribution is made at 275-132 kV, i.e. distribution level voltages are 132 kV and below. Figure 1.1 shows the structure of the UK electricity industry before and after privatisation.

The NGC system, shown in figure 1.2 is the most highly developed power system in the world, consisting of in excess of 7000 kilometres of overhead lines and transmission

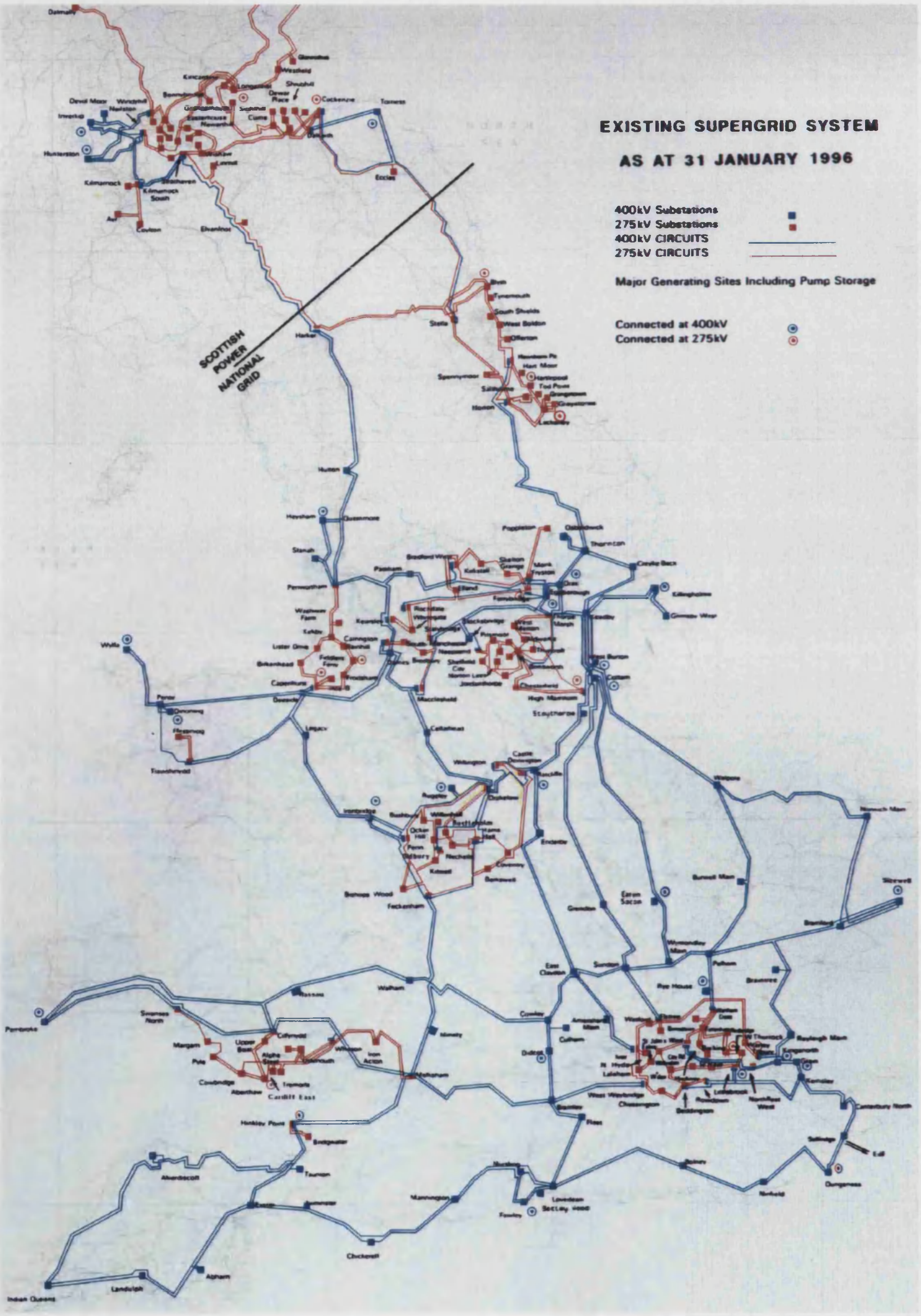


Figure 1.2: Geographical map of the existing supergrid system as at 31 January 1996, reproduced from the 1996 Seven Year Statement with the permission of the National Grid Company.

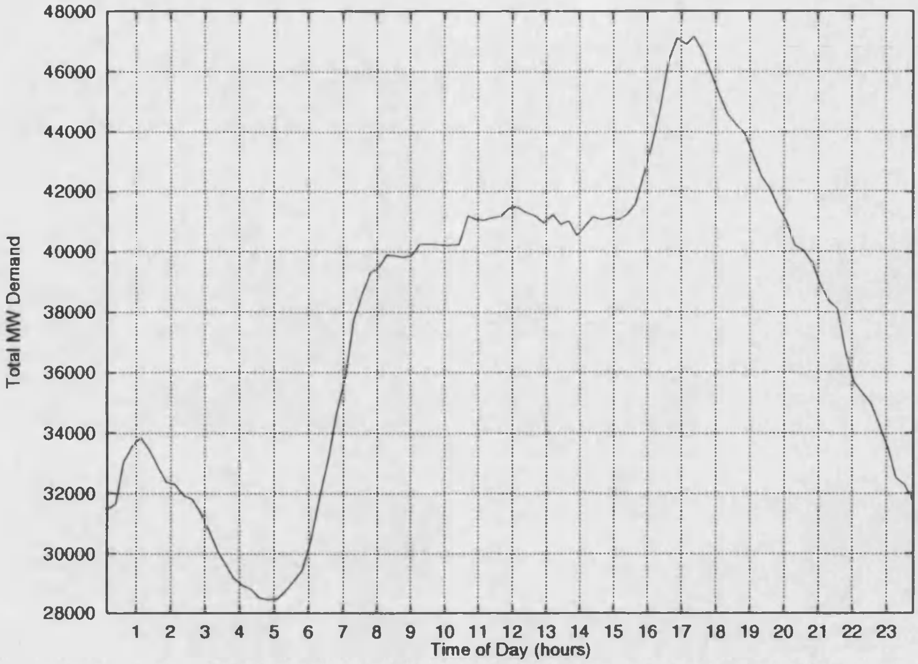


Figure 1.3: A typical winter daily demand profile.

cables, 21,600 pylons and 280 sub-stations. Operation of the system is managed by a central control centre (The National Grid Control Centre) at Wokingham.

1.1.1 Demand

Power is supplied from generators to customers either directly from the NGC transmission system, or via the RECs' systems. Power is taken from the NGC system at busbars known as grid supply points.

A typical winter daily demand curve is shown in figure 1.3. During the day, the demand on the system is high while industrial loads are high, lights are on and so forth. At night, when most of the population are asleep, the demand on the system is correspondingly low. As well as daily trends, the demand on the system will also tend to be lower at weekends than on week days since industrial loads are reduced then.

Clearly, weather and daylight hours will have a very significant effect on demand. On the NGC system, winter peak demand is around 50 GW, while demand in the summer can fall as low as 17 GW [4].

1.1.2 Generation

In 1996/7 the total installed generating capacity on the NGC system is 60.7 GW made up of around 200 large generating units. All generating units connected to the NGC system, with a capacity of 100 MW and above, are centrally dispatched by the NGC. This gives the NGC sufficient control of generation to meet demand and maintain the security of the system.

It is interesting to note how the generating plant mix in the UK has changed over the last few years, since this has had a significant effect on the system infrastructure. Combined cycle gas turbine (CCGT) power stations, using cheap and plentiful North Sea gas have been commissioned in the 1990s. In turn, many older coal and gas fired power stations have become uneconomical and have been closed [5], due to high fuel extraction costs and environmental policies requiring the reduction of sulfurous emissions.

Nuclear power still constitutes a large part of the base generation in the system. However, due to the nature of the fuel, the output of such plant lacks flexibility. Pumped storage schemes are occasionally used to store excess power at times of low system demand. To minimise transmission losses, nuclear power stations and pumped storage schemes are sometimes sited close together.

1.1.3 Interconnections

The NGC system is connected to the power systems of Scottish Power (SP) and Scottish Hydro Electric (SHE) by an AC synchronous link. The link consists primarily of two 275/400 kV transmission lines. There are also two 132 kV lines. The lines connecting the two systems are approximately 150 kilometres in length and are electrically 'weak' in comparison to the infrastructure of the NGC system and the SP/SHE systems. Because there is an excess of low cost generation in Scotland, the interconnection is used to export power from the SP/SHE systems. The capacity of the interconnection was increased to 1600 MW in 1993 [6], although there are plans to increase this further to 2200 MW in the near future [4].

The NGC system is also connected to France via a 2000 MW DC link. This link consists of four pairs of cables between converter stations at Sellindge in Kent and Les Mandarins near Calais. Like the link to SP/SHE, power is almost always imported to the NGC system due to the availability of low cost nuclear generation in France.

1.1.4 The transmission system

Privatisation has stimulated rapid changes in the generation profile in the UK [7]. Many coal fired power stations were situated in conurbations. When they closed, power had to be transported from more remote generation to these load centres. Reactive power losses across an inductive transmission network have required the installation of 20 static VAr compensators (SVCs) and 27 mechanically switched capacitor banks (MSCs) to date, with many more planned. The use of re-locateable voltage compensators [8] is now becoming more widespread since the system can thereby adapt more easily to future changes in generation.

The long distance transport of power has so far required the installation of seven phase shifting transformers, or quadrature boosters [9]. These allow improved balance of power over sets of parallel transmission lines supplying a single area. Increased power flows are thus possible without sacrificing system security or increasing transmission capability.

Much of the new CCGT generating plant is situated in the North East of England where there is comparatively easy access to the North Sea gas supply. However, the large load centres in the UK are in the Midlands and the South East. Consequently, large power flows are experienced from the North to the South. Future increments in the exports from SP/SHE will add to these North-South flows and place an increased stress on the transmission system. Demand on the system is also anticipated to increase at a rate of 1.4% per annum [4]. Despite reinforcements, the security of the system under these conditions is still a significant concern.

1.2 System operation

The primary aim of power system operation is to maintain a continuous electricity supply which meets customer demand, i.e generation must be scheduled to meet system demand and transmission losses. In addition, system voltage and frequency must be maintained within statutory limits. Frequency is maintained by the correct scheduling of active power, while voltage is controlled using reactive power sources.

Meeting demand is a complex process because large power stations or *generation groups* require a certain amount of time to be brought on line or *run up*. This varies according to the plant type, but in the case of coal fired plant can take several hours. Because of these restrictions, demand must be predicted hours in advance, with generation scheduled accordingly. However, uncertainty in demand prediction and potential forced generation outages require that a certain quantity of generation should be on continual standby. This is known as *reserve.* Sometimes, when system conditions change rapidly, reserve generation will be insufficient, or certain transmission limitations may be exceeded. Under such circumstances, the system operator is required to make minute-by-minute alterations to generation in order to preserve system operational standards and security.

1.2.1 The Electricity Pool

Scheduling of generation to meet demand in England and Wales is facilitated by the *Electricity Pool* system [10]. The NGC operate the pool by providing settlement and funds management services. Operation is controlled by a computerised system, known as GOAL [11], fed with data about generation offer prices, plant availabilities, demand and so on.

At 10.00 am each day, every generator bids into the pool system with both pool offer prices and availability for each of 48 half hour periods in the following day. An estimate of demand on the system is also made for each half hour. Generation is then scheduled to meet demand in ascending order by price. This is known as *merit order* scheduling.

The merit order schedule is subsequently revised to take various operational constraints into account. These are described below in section 1.4.

After the day of operation, i.e. once energy has actually 'changed hands', each generation unit in merit is paid *Pool Purchase Price* (PPP) for each MWhr of electricity generated. PPP has two components, the *System Marginal Price* (SMP), and a *capacity payment.* The SMP is the price of the most expensive generation unit in merit, while the capacity payment allows for loss of load which arises when there is a significant *Loss Of Load Probability* (LOLP). Simply,

$$PPP = SMP + [LOLP(VLL - SMP)] \tag{1.1}$$

where VLL is the *Value of Lost Load* which is an index linked value of around £2.50/kWhr at the time of writing. The LOLP is calculated by taking into account the projected availability of generation, load forecast and possible load forecasting errors.

Electricity suppliers pay the pool *Pool Selling Price* (PSP) for each MWhr of electricity used. It covers both the payments made to generators and *Uplift* costs. Uplift makes provision for reserve, constrained running, forecasting errors, ancillary services and marginal plant adjustments. Ancillary services includes payments to generators providing *frequency response* and *black start capabilities.*

Settlement of amounts owed to generators by suppliers takes place over a period of approximately 28 days after the trading day.

1.3 Security

Security describes the power system's ability to meet demand for active and reactive power at all times without compromising the quality of supply or the integrity of plant connected to the system. Implicit to this definition is the power system's behaviour under a number of credible adverse conditions, such as faults or loss of load. These conditions are called *contingencies.* Security itself can be broken down into two main categories; *static* security, and *dynamic* security.

1.3.1 Static security

Static security concerns the loading of plant and nodal voltage levels in the system under steady state conditions, i.e. when all operating quantities which characterise the system can be assumed constant. Transmission and generation plant has thermal ratings which must be observed at all times. In addition, system voltages must remain within statutory limits.

1.3.2 Dynamic security

Dynamic security concerns the dynamic behaviour of the power system following a contingency. Usually it is the post contingency *stability* of the system, rather than momentary overloads and overvoltages, which is of most concern. Depending on the severity of the contingency, or *disturbance* to the system, synchronous generation units will oscillate with respect to one another, or occasionally completely lose synchronism with the rest of the system. Note that a contingency can be a *small* disturbance, such as a shift in loading in the system, or a *large* disturbance, such as a fault on a transmission line. In fact, it is the nature of the disturbance which dictates which tools are required to analyses the stability of the system [12].

1.3.2.1 Transient instability

The nature of the disturbance also helps to define the type of instability. One of the most common forms of instability, and the one which is of greatest relevance to the work described in this thesis, is transient instability. It is characterised by the loss of synchronism of one or more generation units caused by a large disturbance. This subject is covered in more detail in chapter 2.

1.3.3 Security standards

A security standard defines the severity of contingencies for which the power system must exhibit satisfactory performance. Many utilities use an "$N-x$" criteria, where N is the total number of items of plant in the system and x is the number of items of plant which may be lost concurrently without compromise to system security. For example, $N-2$ means that the system should be secure for the concurrent loss of up to any two items of plant. Because of the size of modern power systems, such criteria will be used to formulate a reduced contingency list, concentrating on only the most onerous conditions.

In 1993/4, the NGC conducted an in-depth cost-benefit review of their transmission security standards [13]. The conclusion was that their current security practices provided a high level of reliability which many of their customers would be reluctant to lose. However, NGC have recently relaxed their on-line security criteria of $N-2$ in favour of $N-D$, where "D" is any double circuit. Hence, only single and double line outages need be considered.

1.3.4 Security assessment

The state of the power system is always changing, due to variation of loads, generation and transmission plant. System operators must be able to assess the security of the system minute by minute, as these changes occur, and take preventative or corrective measures when necessary. In order to do this, the system operator must have access to the state of the power system. This is facilitated by transducers on the system which measure analogue quantities, such as voltages and line currents, and digitals, such as the status of circuit breakers. This information is then relayed back to central control centres via the *Supervisory Control And*

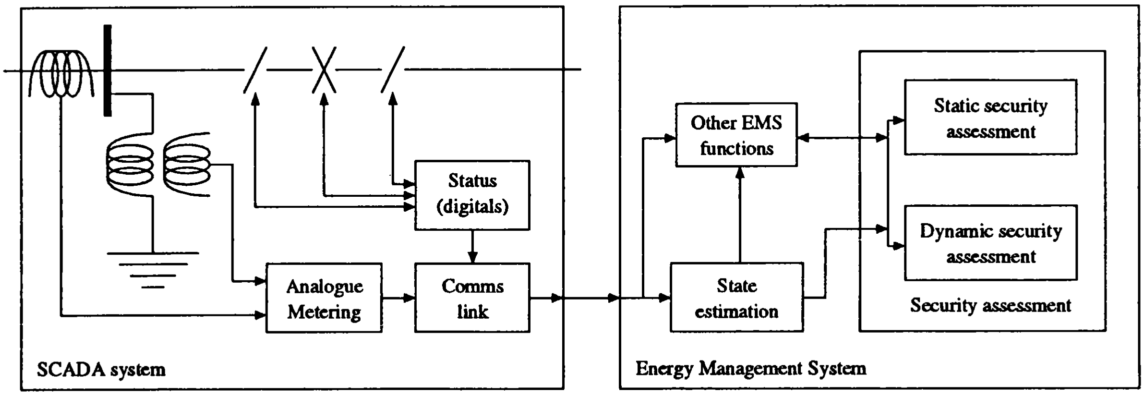


Figure 1.4: State information from the power system passing through the SCADA system to the EMS. EMS functions include state estimation and security analysis.

Data Acquisition (SCADA) system [14, 15]. Finally, bad data will be identified and corrected automatically by *state estimation* software [16, 17].

The state estimation function is normally part of a larger software package, known as an *Energy Management System* (EMS) [18–20], as shown in figure 1.4. This package is generally able to perform several functions, including security assessment. Static security assessment will usually be performed by a load flow. Frequently, an optimal power flow program will be used at this stage [14, 21]. This has the advantage that a new generation schedule, which attempts to reduce operational costs and maintain system security, may be produced [22–24].

Dynamic security is more involved than static security, and therefore more difficult to assess in operational time scales. This is discussed in more detail below in section 1.4.2.

1.4 Constraints

When generating plant is rescheduled to meet security criteria, it is said to have been *constrained.* Generation units which have their output reduced during rescheduling are said to be *constrained off*, while conversely, generation units which have their output increased during rescheduling are *constrained on.*

A voltage constraint, say, describes the need to reschedule generation in order to prevent potential violation of statutory voltage limits. Usually, static security constraints are readily and rapidly analysed using a load flow. On the other hand, the analyses of dynamic security constraints can be significantly more involved and may required the use of transient stability or eigenvalue programs.

1.4.1 Boundary constraints

Dynamic security constraints tend to be complex in nature, particularly when they involve large parts of a power system which may include several generation groups. They can depend, amongst other things, on the generation and demand pattern on the system and the current parameters of control systems, such as static VAr compensators and automatic voltage regulators.

Few tools are available which are capable of identifying dynamic instability in the control room. Additionally, it can be difficult for operators to determine how the system's generation profile should be changed to rectify dynamic insecurity, particularly in the short amount of time during which measures must be taken on line. To help guard against dynamic security problems, and to suggest remedial measures in the event they occur, *boundary constraints* are evaluated off line. These take the form of power flow limitations across 'weak' interconnections in the transmission system.

Boundary constraints are evaluated using a contrived 'worst case' scenario. Demand and generation patterns are set accordingly, and the security of the system is tested using a set of pertinent contingencies. The power transfer across the boundary of interest is then gradually increased or decreased until the maximum amount of power which can be securely transferred is found. Power flow across that boundary is then constrained to this value during system operation. There are three reasons why this approach can lead to excessive constraints:-

① A worst case scenario is used to calculate boundary constraints. In practice, the power system state is unlikely to reach such worst case conditions.

② Even if the power system does attain worst case conditions, it is only likely to do so for a very small proportion of the time for which boundary constraints are imposed. Hence, excessive constraints may be imposed for a large proportion of the time.

③ A worst case scenario will include generation which has a large negative effect on the security of the system. By selectively constraining such generation off, smaller total constraints may be required than if the transfer across a boundary is arbitrarily reduced.

Boundary constraints can also result in an insecure power system if the actual operating point varies significantly from the 'worst case' used during off-line studies.

1.4.2 Dynamic security assessment

The disadvantages of the boundary constraint approach have inspired the development of *dynamic security assessment* (DSA) tools [25] which are capable of explicitly determining the security of the system. So far, efforts have concentrated on transient security since this tends to be most problematic in modern power systems. Either direct methods [1, 26, 27], or parallel implementations of step-by-step time domain simulation are used to obtain the security assessment speeds required on line.

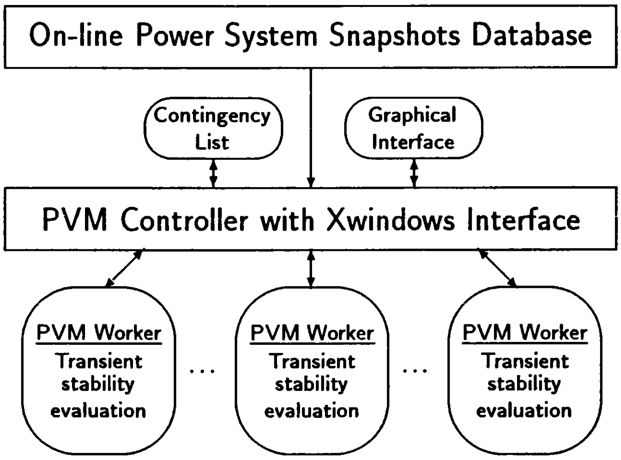


Figure 1.5: Structure of OASIS

Figure 1.5 shows the overall structure of a DSA package called OASIS [28]. Time domain simulations of single contingencies are distributed to a series of computers operating side by side within a parallel computing environment called Parallel Virtual Machine (PVM) [29]. State estimation is used to obtain a consistent 'snapshot' of the power system. The transient stability of this snapshot is then evaluated using a specified list of contingencies. Finally, the results of all the contingencies are classified and ranked by analysis of the rotor swings of generation units in the power system. Results are presented to power system operators via a purpose built graphical user interface.

Tools capable of going a stage further and providing system operators with remedial actions in the event of a dynamically insecure system are still in their infancy [30–32]. Without such tools, boundary constraints still provide the most reliable way of ensuring dynamic security is maintained on line.

1.4.3 Constraint costs

Generation constraints are problematic because they imply an increase in operational costs; more expensive out-of-merit generation must be used in place of cheaper in-merit generation. In the UK, additional payments are made to generators, depending on the position of units in the unconstrained generation schedule and their pool offer prices. These payments are laid out in table 1.1. Note that generation which is constrained off is paid profit, i.e. the difference between PPP and its offer price, while generation constrained on is paid its offer price.

Unconstrained Schedule	Actual Output	Payment
On	On	PPP
On	Off	PPP−Offer price
Off	On	Offer price
Off	Off	Availability*

Table 1.1: Payments made to generators related to unconstrained schedule and actual output. * Availability payment = $LOLP(VLL - Offer\ price)$

From now on in this thesis, pool purchase price and system marginal price will be taken to be the same. In other words, the capacity payment component of PPP will be neglected. This is a common simplification to make for the sort of simulations described later in this thesis, since the LOLP is small and data used in its calculation, such as possible load forecasting errors, is not available. Thus, constraint payments can be simplified to,

$$Constrain - off\ cost = (SMP - offer\ price).g \tag{1.2}$$

$$Constrain - on\ cost = offer\ price.g \tag{1.3}$$

where g is the number of MW constrained.

1.4.4 The impact of constraint costs

A significant proportion of Uplift costs can be attributed to constraints. In the year 1993/4, constraint costs within the UK power network totalled £189M of which approximately £20M were related to transient stability [13]. The proportion of constraint costs related to transient stability is also on the increase [33].

Since 1995, two schemes have been instigated which supplement the NGC's requirement under the transmission licence to operate an efficient and coordinated system. These are the Uplift Management Incentive Scheme (UMIS) and subsequently the Transmission Services Scheme (TSS). These schemes provide extra incentives to reduce the proportion of Uplift costs which the NGC are well placed to control. This is significant because it has further encouraged the adoption of on-line DSA practices to replace the use of boundary constraints. However, as will be seen below, planning practices continue to rely on boundary constraints to make estimates of constraint costs. This may lead system planners to make unnecessary investment in transmission plant.

1.5 Power system planning

Power system planning describes the broad range of tasks involved in evaluating the future development of a large and complex power system. Initially, the need to develop the system must be identified. Possible solutions are mapped out and compared using a set of appropriate criteria, including cost and performance. Finally a development strategy is chosen based on the results of the comparison.

One of the largest concerns during the planning process is the accounting of *uncertainty* during the evaluation of strategies. A number of system development strategies are usually drawn up. The next stage of the process is to list the factors affecting the choice of each strategy. A range of values may be assigned to these factors by assessing the level of uncertainty associated with each. An initial *sensitivity analysis* may be performed so that the problem space can be reduced by eliminating less significant factors. Two approaches are commonly taken from this point; *scenario analysis* or *decision tree analysis* [34].

1.5.1 Scenario analysis

For each expansion strategy, a set of values will be inserted for the significant factors, such as future fuel and land costs. This set of defined factors is known as a *scenario.* The benefit of each strategy can then be assessed by analysing several scenarios and making an evaluation using some suitable criteria, e.g. cost. A further level of evaluation for each strategy is achieved by assigning a probability of occurrence for each scenario. For example, a particular strategy may lead to a high cost if a certain scenario occurs. However, if the scenario is very unlikely to occur, this may only be a minor concern and the risk correspondingly small.

	Scenarios			Expected cost of the strategy
	A	B	C	
Strategy 1	100	116	144	119
Strategy 2	120	118	124	120
Strategy 3	128	104	120	*114*
Probability	0.25	0.5	0.25	

Table 1.2: Table showing how overall expected cost might be worked out given three scenarios A, B, and C with probabilities of occurrence 0.25, 0.5 and 0.25 respectively

Table 1.2 shows the evaluation of three hypothetical strategies based on a least cost criteria. In this case, strategy 3 would be chosen.

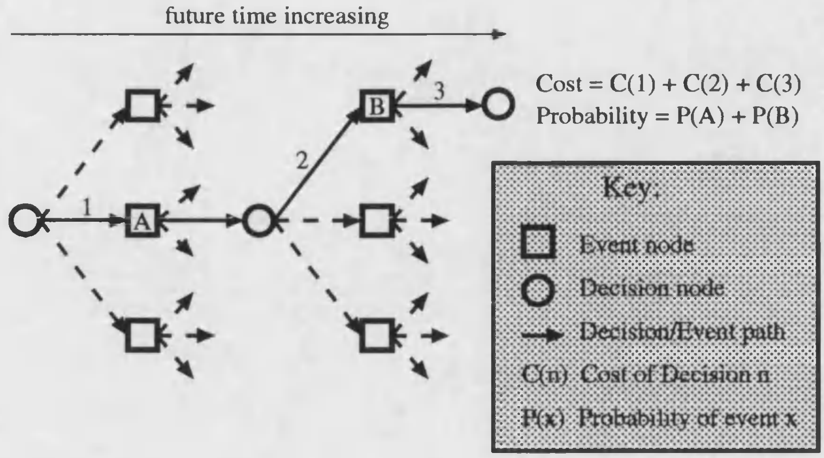


Figure 1.6: An example of a decision tree taking account of decisions 1,2 and 3 made after events A and B.

1.5.2 Decision tree analysis

Events and post-event decisions are mapped out in a tree. Probabilities for each future event and decision can be assigned to the branches of the tree so that each strategy can be evaluated. This means, in effect, that each branch of the decision tree is equivalent to the conditions describing a discrete scenario.

Figure 1.6 shows a decision tree for one strategy. Each of the terminal nodes represents a scenario, having a certain cost and probability of occurrence. All strategies under consideration can be analysed in this way, permitting a choice to be made based on the expected cost for each.

1.5.3 Multiple Objectives

It is worth mentioning that the suitability of development strategies must be evaluated in relation to certain criteria, termed *objectives.* In the context of system development, many objectives must be taken into account, including cost, environmental impact, adherence to company policies, etc. Evaluating *multiple objectives* simultaneously can be complicated, and it may be interesting to look at the effects of changing the weighting given to each objective. Linear programming techniques have conventionally been popular in this area [35], although fuzzy logic is now receiving more widespread application [36].

1.6 Power system planning in the UK

The development of the planning tool described in this thesis was motivated by the interests of the NGC. It is therefore appropriate to look in detail at the planning perspectives and methods of the NGC which are of relevance to the work described in this thesis. It should be made clear, though, that whilst the NGC provides a good 'case study', the methods described here are relevant to any utility which attempts to operate a power system in an efficient manner, using the cheapest generation to supply their customers' needs.

Due to the significant proportion of operational costs which may be attributed to constraints, an estimate of the constraint costs associated with potential future network configurations is essential to the system planning engineer. Constraint cost estimation is presently performed within the NGC using a program called ESCORT. A description of this is given below in section 1.6.2.

1.6.1 Motives for development

The motivation to develop the power system comes from one of two perspectives. Often a generator will recognise an opportunity based on future demand for electricity and the costs of building and operating new plant. The other perspective is that of the transmission company. Future demand is again a factor, but commissioning and de-commissioning of generation plant must also be taken into account. Occasionally, the motivation for system development will come from a recurrent operational problem.

Generators must consider the cost of their connection to the system. Any necessary infrastructure improvements are usually paid for indirectly through use of system charges. For example, on the NGC system, generation sited in zones of the system which tend to import remotely generated power are paid a tariff for each MWhr of electricity generated. Conversely, generation sited in zones of the system which tend to export power must pay a tariff for each MWhr of electricity generated.

Other considerations when choosing where to connect include land cost, fuel cost and availability, work force, water supply for cooling, environmental acceptability of location and so on. More indirect factors may also have an influence, such as interest rates and government policies.

It is the responsibility of the NGC to develop and maintain an efficient, co-ordinated and economical system of electricity transmission and to facilitate competition between generators. One element of this undertaking is achieved by meeting the demand on the system with the cheapest set of generation available, i.e. operation of generation in merit order. A recognised problem in the UK is that, despite the use of tariff zones, the cheapest generation is often sited away from demand centres and power must be transmitted in bulk over long distances [37]. Thus, if significant constraint costs are not to be incurred, the transmission system must under go continual reinforcement to allow for new generation coming on line.

1.6.2 Estimating constraint costs

The economic consequences of a change to the transmission network include variation in operational constraint cost. The ESCORT program (Economic and Security Costing Of Reinforcements to the Transmission system) [24, 38], developed by the CEGB and subsequently the NGC, is currently used to furnish power system planners with estimates of the constraint cost for a given network. Generation groups are scheduled to meet demand, while taking possible contingencies into account. ESCORT will allow both forced and planned generation and transmission outages to be modelled probabilistically.

Initially, all generation units and transmission lines on planned maintenance are removed from the network according to a given maintenance schedule. Random maintenance is then applied to the remaining plant. This must conform to a set of maintenance rules because certain concurrent outages would not be permitted on the real system, e.g. maintenance of all the lines connecting an available generation unit. Finally, a random breakdown trial is applied to each remaining item of available plant.

ESCORT then calculates the costs associated with meeting a set of power flow constraints. This is achieved by using a DC load flow to calculate a set of power flows. Transmission losses are linearised to facilitate the use of a linear program for calculating generation schedules which meet all power flow constraints.

Several such simulations are carried out by ESCORT in order to model changes in plant availability and demand over a given period of system operation.

Because the program is built around a DC model of the power system, voltage and dynamic constraints must be represented as boundary constraints. These are calculated externally using other analysis tools, such as an AC load flow [39] and transient stability program [40]. As with the on line use of boundary constraints, their inclusion here results in unnecessary constraints. In turn, the consequence of this is an over estimate of constraint costs and a tendency to invest too heavily in the transmission system.

1.7 This work

Part of the task of assessing reinforcement to a power system is to make estimates of the constraint costs which will be saved by doing so. A DC load flow and linear program approach is satisfactory as far as static thermal constraints are concerned. However, power system dynamic constraints are becoming increasingly prevalent as thermal reinforcements are made and long term generation profiles change. To incorporate such constraints into the framework of a DC load flow requires the external evaluation and imposition of boundary constraints which result in excessive estimates of the costs.

The aim of the work presented in this thesis was to develop a tool which explicitly evaluates the constraint costs arising from the operation of a *transiently* secure power system. To do this, it has been necessary to develop an approach which will automatically identify the most cost effective generation in the system to constrain. Time domain simulation methods proved to be unsuitable on their own for this task, inspiring considerable research into direct, or quantitative stability methods. The short-falls of these led the author to develop a new quantitative stability method, building on research previously conducted at the University of Bath [41, 42], into the use of artificial neural networks and composite indices.

To gain an estimate of constraint costs which takes into account the year-around diversities in system operation, it has been necessary to develop an appropriate probabilistic framework. Thus, instead of trying to contrive a worst case scenario, which may not be realistic, many likely system operating points can be modelled and analysed.

The software suite which implements the methods described in this thesis is called CAMEL (*C*onstraint *A*nalysis using *M*onte *C*arlo *E*valuation of *L*oading).

1.8 The rest of this thesis

Chapter 2 looks in detail at the subject of power system stability. The different classes of instability are described and related to the types of disturbance which cause them. Of particular relevance to the work in this thesis is the phenomena of transient stability, which is sub-divided into first-swing and subsequent-swing transient stability. The causes of each are generally different, with subsequent-swing instability tending to be more complex. Voltage instability and inter-area oscillations are also covered in this chapter.

Chapter 3 looks at methods which can be used to avoid transient instability. The chapter is divided into three main parts. The first part examines the relationship between the transient stability of the system and the active output of generation groups. The second part uses this information to select a suitable strategy for calculating generation changes required to restore system stability. This strategy is implemented as part of the method described in chapter 6.

The third part of this chapter is a brief review of operational and planning measures which can be taken to improve the transient stability of a power system. This section is included for completeness and to provide the reader with some insight into features of the system which may be good indicators of transient stability.

Chapter 4 reviews 'classical' quantitative stability methods. These are direct transient stability methods which may be used alone, or to supplement time domain simulation techniques, in order to provide a measure of the system's proximity to instability. The two methods which are given most attention in this chapter are the equal area criterion and the transient energy function. Composite electromechanical distance methods are also reported on since the author has taken advantage of such a method to enhance the approach described in chapter 5.

Chapter 5 describes the new quantitative stability method which has been developed as part of this work. Results obtained for both first swing and subsequent swing transient stability are presented. The results for first swing instability are compared with the hybrid transient energy function. The new quantitative stability method performs a vital function within the overall algorithm implemented in the CAMEL software.

Chapter 6 is a thorough walk-through and justification of the selection of the models and algorithms contained in CAMEL. The first part of the chapter concentrates on the probabilistic model used in CAMEL to generate likely system operating points. Transient stability assessment and, importantly, the calculation of low cost constraint actions, form the remainder of this chapter.

Chapter 7 presents some typical results obtained using CAMEL and suggests how the program might best be set up for a given power network. The improvement in constraint cost estimation with the methods described in this thesis is implied from the analysis of results. Comparisons between different models and power networks is made using constraint costs evaluated by CAMEL.

Chapter 8 suggests future directions for the work described in this thesis, including the possible adoption of some of the techniques in the on-line environment.

Chapter 9 presents the conclusions of this work.

Chapter Two

Power System Stability

The establishment of an interconnected network of generators and loads was originally made for reasons of economy and improved continuity of supply, or reliability. Today continuity of supply is almost taken for granted on large power systems, and emphasis tends to be placed on the quality of supply. The criteria of voltage and frequency are used to measure this, for which limits of $\pm 5\%$ and $\pm 0.2Hz$ are typical. Levels of noise or harmonics must also be maintained within specified tolerances.

Modern power system generating units usually consist of a steam turbine driven synchronous machine. Control systems regulate the machine's mechanical torque input and terminal voltage. Because the machine's terminals are connected to the power system, synchronism must be maintained for effective power transfer. Loss of synchronism is reflected by acceleration of the machine's shaft which can cause physical damage due to excessive torques, rotational forces and heating. Loss of synchronism may also lead to unacceptable voltage and frequency deviations on the system.

It is the loss of synchronism of individual machines, and groups of machines, which is the main subject of this chapter. Different forms of stability are discussed, and the overall stability of the system placed in this context. Attention is drawn to *inter-area oscillations* which are often relevant when large groups of closely coupled machines are connected by weak links. Inter-area oscillations have been experienced in the past on the CEGB-SP/SHE interconnection [6, 43].

2.1 Power system disturbances

For the purposes of analysis, a power system is considered to be in *steady-state* when all the quantities that characterise it are constant. A *disturbance* is defined as a change or sequence of changes occurring on the system. For instance, a short circuit on a transmission line followed by the resultant protection scheme operations is described as a single disturbance when analysing power systems.

A distinction is made about the size of a disturbance based on the techniques suitable to analyse the ensuing behaviour of the power system. If a linear model of the system is sufficient for analysis, the disturbance is classed as a *small disturbance*, otherwise it is a *large disturbance*. Note that a typical contingency such as a double circuit outage would be considered to be a large disturbance.

The work presented in this thesis is only concerned with the post-fault behaviour of a power system caused by the inception of a contingency, which is a large disturbance. However, small disturbances and steady-state instability are covered below both for completeness and because they are relevant to subsequent swing transient instability.

2.2 Steady-state instability

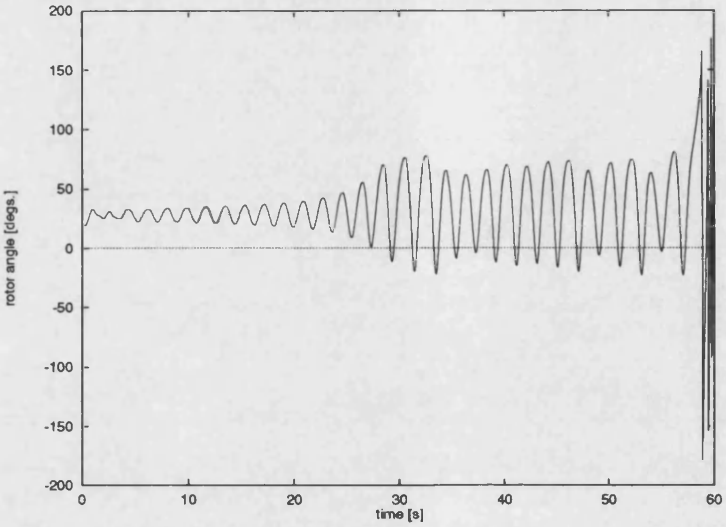


Figure 2.1: A rotor angle vs time plot for a machine experiencing steady-state instability obtained using *PowSim* [110].

A power system exhibits steady-state instability if, following a small disturbance, the power system fails to reach an acceptable steady state operating condition, or reaches a new steady state condition which is significantly removed from the original steady-state operating point. An example of steady-state instability caused by a demand and generation shift is shown in figure 2.1.

Power systems are never truly in steady-state. Incremental changes in demand and generation are occurring all the time which may be considered as small disturbances. Since the disturbance is small, it should be sufficient to linearise the pre-disturbance steady-state condition and determine its stability using some suitable criteria, such as the positions of the system's eigenvalues [44–46]. However, even small disturbances can cause non-linear plant modes to shift, thereby moving the position of the system eigenvalues. This can often move the system operating point into the stable domain.

The steady-state stability limit of the system is reached when an arbitrarily small change in any pre-disturbance operating quantity in an unfavourable direction leads to loss of post-disturbance system stability.

2.2.1 Oscillatory and monotonic instability

Oscillatory instability and monotonic instability are forms of small-signal instability which can be identified by resolving the torque of machines in the system into synchronising and damping components [12, 47, 48]. Following a disturbance, the change in electrical torque, ΔT_e, can be written as

$$\Delta T_e = T_S \Delta\delta + T_D \Delta\omega \tag{2.1}$$

where $T_S \Delta\delta$ is the synchronising torque and $T_D \Delta\omega$ is the damping torque. T_S and T_D are the synchronising and damping torque coefficients respectively.

Monotonic instability is caused by a lack of synchronising torque and is characterised by a steadily increasing machine rotor angle through a non-oscillatory mode. This form of instability is rare in modern power systems where most machines are fitted with AVRs.

Oscillatory instability is caused by a lack of damping torque and is characterised by the building up of machine rotor angle oscillations. This build up may stabilise at a constant amplitude, a state known as *hunting*. More seriously, machine pole slipping may occur as in figure 2.1.

Steady-state instability in modern power systems generally takes the form of oscillatory instability, the main causes of which are poorly designed plant control systems and weak tie lines between groups of closely coupled machines. The latter is covered below in section 2.5.

Oscillatory instability has been linked to the characteristics of fast machine excitation systems [6, 43, 49]. Although they improve transient stability, these systems tend to adversely affect steady-state stability. One solution is to use power system stabilisers which feed back an acceleration signal into the main AVR loop of the machine [50].

Other causes of oscillatory instability are related to the modes of control equipment, such as high voltage DC converters and static VAr compensators (SVCs). These problems are well understood and can be negated by observing good design techniques [51].

2.3 Transient instability

A power system exhibits transient instability if, following a large disturbance, the system fails to reach an acceptable steady-state operating point, or performs unacceptably when reaching a new steady-state operating point. An example of transient instability is shown in figure 2.2.

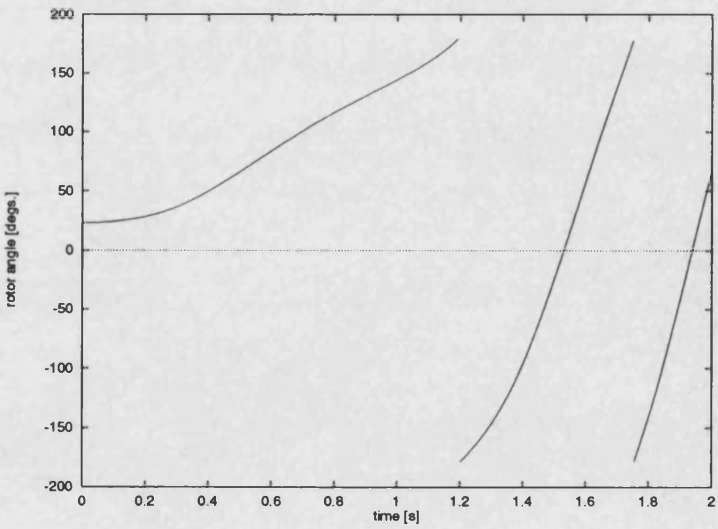


Figure 2.2: A rotor angle vs time plot for a machine experiencing first swing transient instability obtained using *PowSim*

This definition of transient instability is clearly dependant on what is deemed to be an acceptable steady-state operating point and what is deemed unacceptable system performance. NGC plan the system so that for all $N-2$ contingencies, synchronism of all machines connected to the system is maintained during and after the disturbance. Also, the steady-state post disturbance levels of voltage and plant loading should be within specified tolerances.

More sophisticated criteria are sometimes used, particularly for off-line studies. These include the magnitude of the first swing of each machine and the time taken for all subsequent rotor oscillations to be damped out. Typical criteria would be a maximum swing amplitude of 100 degrees and a time constant of 12s for the envelope created by the rotor angle swing peaks. Figure 2.3 shows how an exponential curve can be fitted to decaying rotor swing oscillations. This curve can then be used to find a decay time constant. In fact, the best way of determining the curve coefficients is to take logarithms of the peaks on the swing curve and fit a straight line to the resulting points [28]. The gradient and intercept of the line give the exponential coefficients.

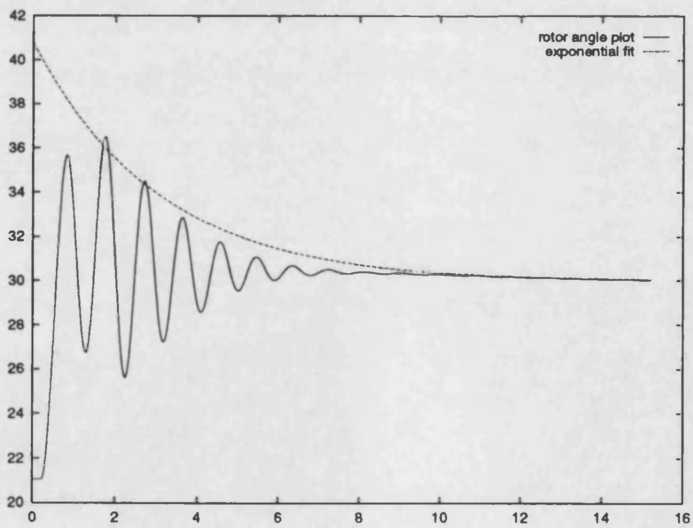


Figure 2.3: A rotor angle vs time plot with a 'best fit' exponential drawn on to show how a time constant may be obtained for decaying rotor oscillations.

It is often useful to subdivide transient instability into two classes; *first swing* and *subsequent swing.* First swing instability is usually the result of a severe fault electrically close to the terminals of a generation unit. The large power imbalance caused by the sudden loss of exportable electrical output power causes the machine's rotor to rapidly accelerate. An example is shown in figure 2.2.

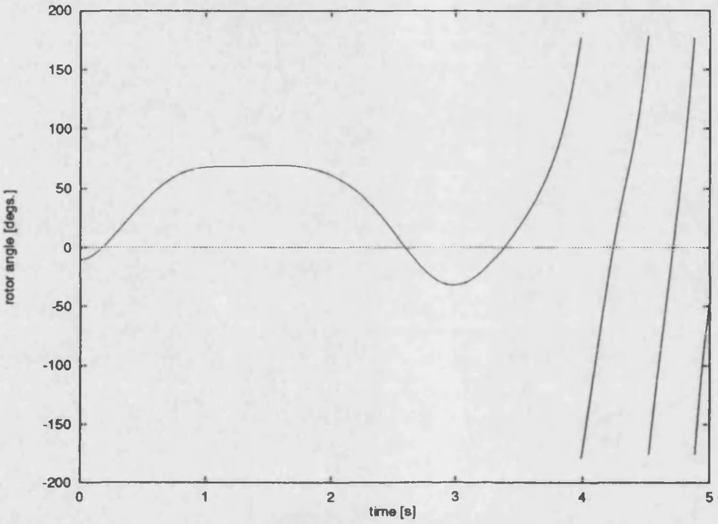


Figure 2.4: A rotor angle vs time plot for a machine experiencing subsequent swing transient instability obtained using *PowSim*

Subsequent swing instability, an example of which is shown in figure 2.4, is a more complex phenomena. It can be caused in one of two ways:

① The system post fault operating point may be steady-state unstable.

② Interaction between different modes in the system may contrive to perturb the rotor of one or more machines beyond 180 degrees.

Distinguishing between these two causes of subsequent swing instability is not straightforward. Deciding whether the post fault operating point of the system is steady-state unstable is problematic for two reasons. Firstly, an instant in time when the post-fault operating point at which to linearise the system must be selected. Secondly, techniques such as eigenvalue analysis can give misleading results as outlined in section 2.2.

Identifying interaction between modes of oscillation is also a complex process, especially when it is considered that the number of possible modes of oscillation in an n machine system is $n - 1$. A method is described by Lin et al in [52] using the normal form of vector fields. Often it is useful to group machines together into *coherent clusters* [53, 54]. These are groups of machines which follow similar trajectories during a disturbance. Various techniques have been applied in this area, including multivariate analysis [55–57], frequency component analysis [58] and Taylor series expansions [59]. However, in order to find interactions between groups, it may be necessary to look at system power flows [60] or machine energies. This is discussed in chapter 4.

2.3.1 Transient stability limits

The transient stability limit for a particular disturbance or set of disturbances is the steady-state operating point for which the system is transiently stable, but for which a small, unfavourable change in any of the operating quantities renders the system transiently unstable.

Note that this definition means that it is only appropriate to define a transient stability limit in terms of a set of disturbances or *contingencies*. This is particularly relevant to the work described in this report. It is impractical and unnecessary to use a full set of contingencies to determine the transient stability limit of a certain part of the system. Instead, a reduced set of contingencies should be selected by some appropriate criteria.

2.4 Voltage instability

Voltage instability is characterised by a local uncontrolled change in voltage following any disturbance [61, 62]. It is generally caused by a lack of reactive power to support system voltage in areas supplied by transmission lines with high impedances.

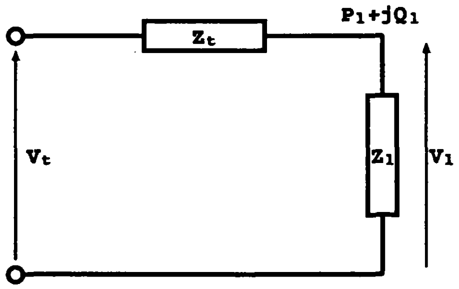


Figure 2.5: Simple circuit to illustrate the principle of voltage instability.

Consider the circuit shown in figure 2.5. P_l is an active load of impedance Z_l being supplied through a transmission system with impedance Z_t. The source voltage, V_t will be considered to be constant. The load voltage, V_l varies depending on Z_l and Z_t. Initially, Z_l is far greater than Z_t and hence the voltage across Z_l is approximately equal to V_t. Load is then increased by decreasing Z_l. Now, although the current drawn by the load increases, the voltage across it will fall, and power $P_l = V_l Z_l$. Maximum power transfer to the load is achieved when $Z_l/Z_t = 1$. If Z_l is decreased beyond this point, the amount of power absorbed by the load will decrease. Clearly then, control of power by changing load impedance can be unstable when this limit is exceeded and voltage instability will result. Indeed, it comes as no surprise that load shedding has been used as a method of preventing voltage instability [63].

The characteristics of the load play a large part in determining the mode of voltage instability. For instance, the voltage across a constant impedance load will simply stabilise at a low value which system operators would deem unacceptable. Alternatively, the voltage across a constant power load will simply collapse as described above. On-load tap changing transformers add an extra complication.

When the voltage across the load falls, the transformer will tap change to try to restore nominal voltage. However, the equivalent impedance seen by the system will decrease, further driving down the load voltage. Again, this is positive feedback and results in voltage instability. Tap change 'blocking' can be used to prevent this [64].

The load power factor also affects the load voltage/power characteristic, see figure 2.6. A load with a leading power factor will tend to maintain the load voltage, allowing greater power transfer from the system before voltage instability occurs. However, when voltage instability does finally occur, the 'knee point' voltage will be higher than that at a lagging power factor.

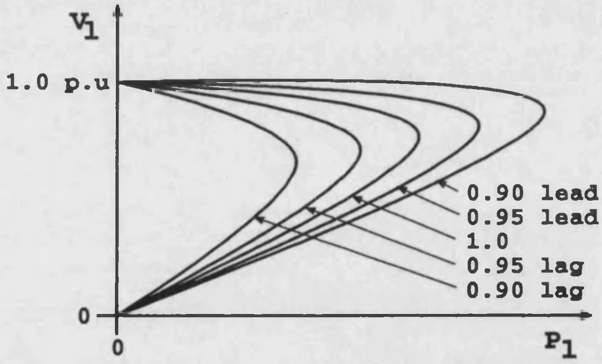


Figure 2.6: Load voltage/power characteristics for different power factors.

Of course, the explanation of voltage instability presented above is simplified. In large power systems, voltage instability is a function of generation reactive power limits, transmission network structure and load characteristics. In addition, observation of the phenomena can be complicated by the fact that machine instability may occur as a result of voltage instability or vice versa.

2.4.1 Voltage collapse

Voltage collapse is more involved and is usually the consequence of a sequence of events occurring together with voltage instability. A low voltage profile across a large area of the power system may result.

Voltage collapse is generally the result of a lack of reactive power reserve [65, 66]. Consider the system in figure 2.5 again. The load voltage could be maintained at its nominal value by the presence of a variable reactive power source connected in parallel to the load. However, practical reactive power sources have limits on their reactive capability. For example, a typical SVC characteristic is shown in figure 2.7. The SVC's reactive power limit is reached at 150 MVAr, after which the reactive power output is given by a BV^2 relationship. Thus, as voltage begins to fall, the reactive output of the SVC drops causing the voltage to fall further. Deployment of SVCs can therefore give the type of load voltage/power characteristic shown in figure 2.8. Voltage instability occurs very rapidly once the SVC reactive power reserve is exhausted.

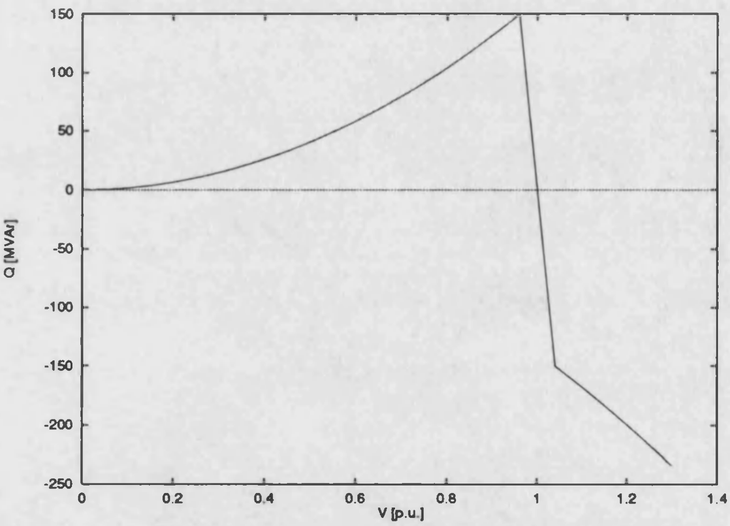


Figure 2.7: A typical Q/V SVC characteristic

Voltage instability is a consideration in systems where load is remote from sources of generation and power is transmitted long distances across a weak transmission system [47]. Voltage compensating devices close to load centres are common in such systems and therefore increase the potential for sudden voltage collapse.

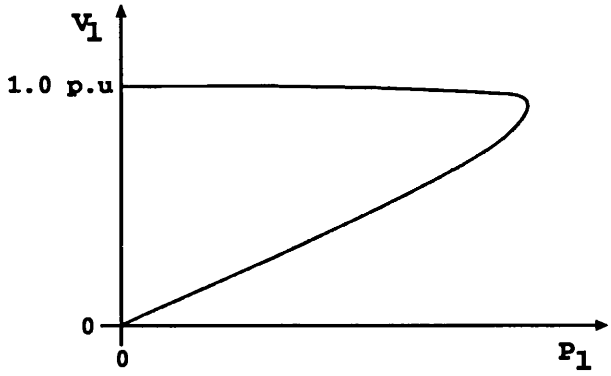


Figure 2.8: Load voltage/power characteristic for a load with voltage support provided by a limited reactive power source.

2.5 Inter-area oscillations

Power system interconnections are beneficial for reasons of economy and security. Reserve requirements can be shared, while cheap surplus generation in one area may be exploited to meet demand in another. For example, the NGC system is connected to France by a 2000 MW DC link and to SP/SHE by a 1600 MW synchronous AC link [4]. With the aid of better analysis tools, transmission plant now tends to be better utilised and the capability of interconnections is stretched to transmission limits as economic, environmental or political circumstances change.

A frequent problem with power system interconnections is their electrical strength. In contrast to the infrastructure of a power system, which is developed over a long period and becomes highly meshed, interconnections usually consist of only a few transmission lines. Thus they tend to be electrically 'weak'. In the past, this weakness has meant that the thermal limits of transmission plant have been reached, requiring reinforcement. As a consequence, the stability limits of the transmission system have been uncovered, and in particular those associated with inter-area oscillation. A comprehensive review of utility experience is given in [67].

Inter-area oscillations are characterised by a low frequency mode of oscillation (typically 0.1-0.8Hz) between weakly connected parts of a large power system [47]. The lowest frequency mode is caused by all the machines in one area of the system swinging in opposition to the machines in the other part. Oscillations can be initiated both by large and small disturbances and contributory factors include the dynamics of AVRs, system topology, location of generation, and load characteristics.

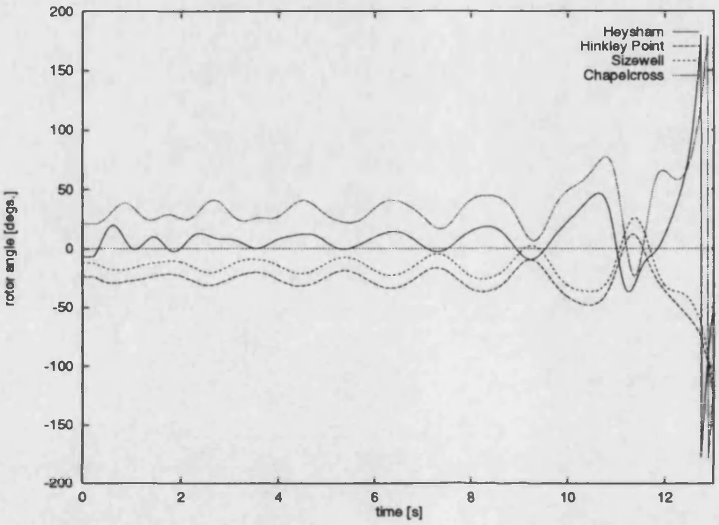


Figure 2.9: A rotor angle vs time plot illustrating inter-area oscillations for a fault at Penwortham obtained using *PowSim*. Heysham and Chapelcross are north of the fault while Hinkley Point and Sizewell are south.

An example of inter-area oscillation caused by a contingency in the north of the UK NGC system is shown in figure 2.9. The disturbance causes the machines north of the fault to swing in opposition to those south of the fault. For clarity, just two machines either side of the fault are shown; Sizewell and Hinkley Point in the south and Heysham and Chapelcross in the north. Machines in both parts of the system stay in relative synchronism due to the tight coupling between them, but the two groups of machines swing against each other with growing oscillation until instability occurs at 12-13 s.

One cause of inter-area oscillations which has previously been identified is the deployment of high gain AVRs [6, 43, 49]. While these improve transient stability, they can have a negative effect on steady-state stability. The solution to this problem is to provide extra damping by fitting such AVRs with robust power system stabilisers (PSSs) [68]. Extra damping can also be provided by the installation of fast response SVCs [69] at key points in the system, an added benefit of which is that some degree of power factor correction occurs. This helps to maintain larger generation stability margins by lowering initial load angles. *flexible AC transmission systems* (FACTs) [70] have also been used in this way.

However, it should be appreciated that the phenomena of inter-area oscillation tends to be more involved than simple control system interaction. In many cases, it is still poorly understood and results in conservative on-line system operation. Frequently, a large number of participating systems are involved. In [71], the authors present a qualitative study into factors which are believed to affect the nature of inter-area oscillations, while a method to identify participating machines is presented by Vittal et al in [72].

Chapter Three

Transient Instability Relief

Transient instability was described in section 2.3. This chapter looks in depth at how transient instability can be avoided.

The algorithm described in chapter 6 of this thesis is required to stabilise a transiently insecure power system. In particular the system's active generation is constrained to achieve this. To understand how this should be done, the relationship between stability and generation is examined in the first part of this chapter. The second section goes on to describe various methods for finding suitable generation changes, together with discussions of their advantages and disadvantages.

For completeness, the third part of this chapter looks at system design considerations which affect the transient stability of the system. In addition, system operational procedures which may help to ensure the transient stability of the system are also given. These are relevant to the planning task because the way in which the system is operated has an inherent bearing on the way the system must be planned and designed.

The third part of this chapter also serves to demonstrate that any method which is used to calculate generation changes must be capable of dealing with diversities in the structure of the power system and the way in which it behaves for a particular generation and demand scenario.

3.1 Transient Stability Characteristics

The relationship between transient stability and generation pattern is non-linear. A second order approximation is in fact quite realistic [73]. In order to examine the stability domain, it is necessary to have access to an index which correlates well with the true stability of the system. Critical clearing time (CCT) is generally accepted as the benchmark power system stability index. Figure 3.1 shows how the CCT for a particular contingency might vary with the output of one generation unit.

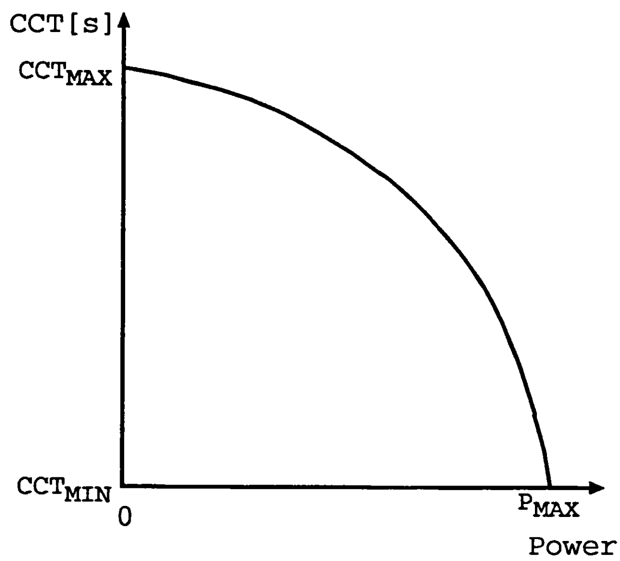


Figure 3.1: Variation of CCT with generation unit power output change.

An increase in power output results in the reduction of the CCT. At maximum power output, P_{MAX}, $CCT = CCT_{MIN}$, while at zero power output the CCT attains a maximum value of CCT_{MAX}. This sort of curve is typical for a generator which is able to aid stability restoration, provided the system *mode of disturbance* does not change as will be discussed below.

The power output of some generation units will be more closely tied, or *sensitive* to the stability of the system than others. In other words, changing the output of one generation unit by the same amount as another will increase the CCT of the system by a different amount. Purely on stability grounds, it is best to alter the output of the most 'stability sensitive' unit as this will require the smallest change in unit output power.

3.1.1 Change of mode of disturbance

The *mode of disturbance* (MOD) is the set of generation units in a system which tend to loose synchronism when a specific contingency is applied. They are sometimes described as the set of units which 'split away' from the rest of the system. Note that this subject is discussed in more detail in section 4.3.5.2.

Large initial gains in system stability can be experienced when reducing the output of a certain generation unit, i.e. the gradient of the CCT/power output curve will be high. However, sometimes this gradient will rapidly decrease. This is because the operating point of the system has changed such that the MOD has changed. A sample curve is shown in figure 3.2 to illustrate this.

A change in MOD resulting in the effect described is most often caused by two or more predominant overlapping modes of oscillation. The most unstable mode will tend to 'mask' the subsequent more stable modes. Consider a MOD consisting of a single generation unit. The unit can be made more stable by reducing its power output, which in turn will increase system stability. This is the area of operation described by the steep section of the curve shown in figure 3.2. Eventually, as this mode is made more stable, another previously masked mode will take precedence as

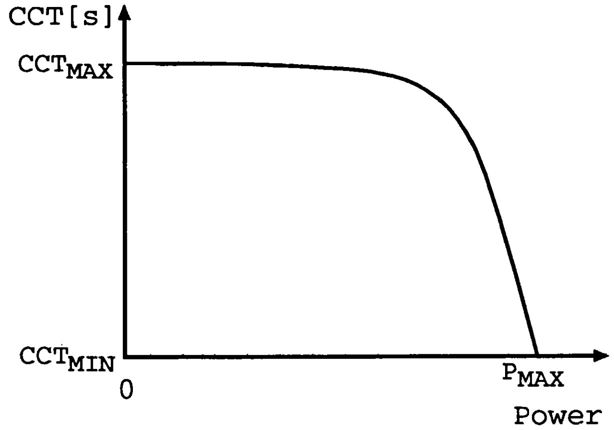


Figure 3.2: CCT verses generation unit power output curve with mode of disturbance change.

the MOD. After this point, the single unit used previously is no longer part of the system's MOD and reduction of its power output will not be of benefit to the stability of the system. Operation is now in the 'flat' section of the curve in figure 3.2.

3.1.2 Change in the number of generation units

A discontinuity in the stability of the system is experienced by changing the number of generation units when adjusting the output of a generation group. This arises because a step change is made to the inertia of the group and the impedance seen by the network at the connection point. In simulation studies, a single equivalent machine is used to model groups of machine sets with common AVR and governor models [47]. Because generating units are not normally run part-loaded (except to meet constraints) it is consistent with system operational practices to change the parameters of the equivalent machine when the output of the whole generating group is reduced such that stability can be sustained by fewer single units.

Consider a situation where the output of a generating group is 1501 MW and the capacity of each unit in the group is 500 MW. Four of these units will be needed to meet the output of 1501 MW and each unit will be 75% loaded. This configuration is more stable than if the output of the group is reduced to be 1500 MW and only three 100% loaded units are used. An example of the type of discontinuity in system stability experienced is shown in figure 3.3.

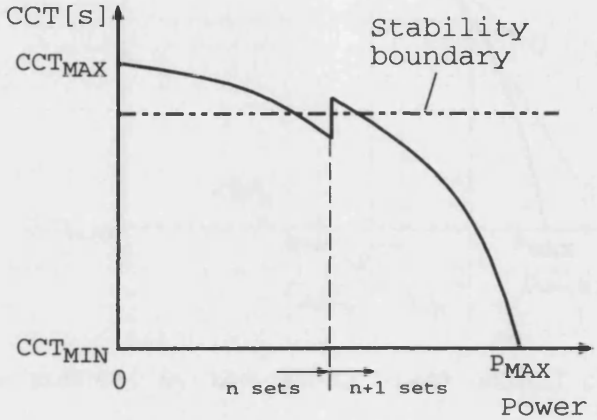


Figure 3.3: CCT verses generation unit power output curve with change in the number of sets ($n \rightarrow n+1$).

If the discontinuity is close to the stability boundary as shown in the figure, there could be two points of operation for which the system is stable without a stable operating point in between. Usually the solution which yields the smallest change in generation group output is preferable from an economic perspective.

3.2 Calculating generation changes

It is possible, by linearising transmission losses, to turn power system thermal security into a linear problem. This facilitates the application of linear programming techniques to find new secure generation patterns [24]. In contrast, it has been shown that the relationship between power system stability and active generation is non-linear. This makes the direct application of linear methods unsuitable without certain restrictions. This is examined below.

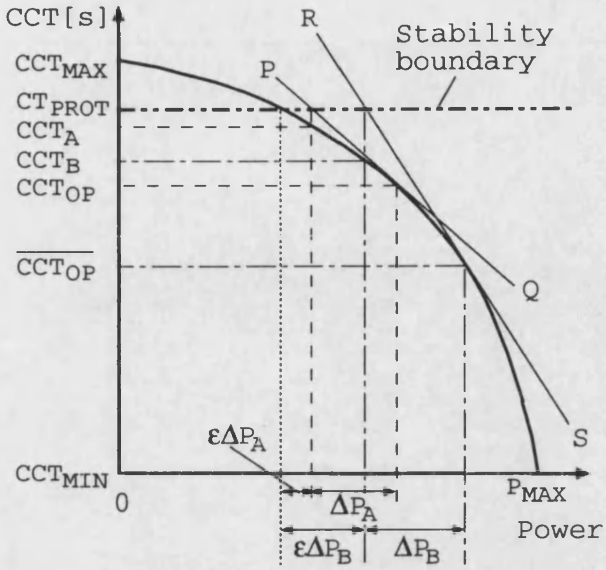


Figure 3.4: Errors incurred by the use of linear critical clearing time (CCT) sensitivity.

Consider again the CCT/output power relationship introduced in section 3.1 which has been redrawn in figure 3.4. The maximum clearing time (CT) for the given system and contingency, limited by the protection equipment say, is CT_{PROT}. At the current operating point the CCT for this contingency is CCT_{OP} where $CCT_{OP} < CT_{PROT}$, and the generation unit output is to be changed so that the system is made stable for a $CT \leq CT_{PROT}$. The shape of the CCT/power output curve is unknown, but a linear approximation can be found at the current operating point. This is shown on the diagram as tangent PQ and is to be used to calculate the generation power change ΔP_A necessary for stability. The error associated with this linearisation is $\varepsilon\Delta P_A$. The corresponding CCT with the change in generation ΔP_A is CCT_A which is less than the CT_{PROT}, so the system would still be unstable for this generation change. Progressive re-linearisations would thus be necessary if CCT_A is to converge to CT_{PROT}.

Suppose now that the operating point of the system is further away from being stable and the CCT is $\overline{CCT_{OP}}$. Using the same linearisation technique with tangent RS, the change in generation unit output would be calculated to be ΔP_B. The error in this value is $\varepsilon\Delta P_B$ which is far greater than $\varepsilon\Delta P_A$. The number of linearisations needed to calculate a reliable value of ΔP_B with a corresponding stable CCT would therefore increase.

3.2.1 Proposed method

Clearly the over extrapolation of a linear approximation to the CCT/power curve can result in large errors in ΔP. There are methods which could be used to reduce this error. For example, second order sensitivities could be used, or a value of the error $\varepsilon\Delta P$ could be estimated. The latter of these two techniques is dangerous because, as the example shows, the size of the error is obviously dependant on the magnitude of ΔP required to restore stability. Second order sensitivities potentially offer a greater degree of accuracy, but are also prone to errors if the average parameters of the curve vary significantly from the point where the sensitivities are calculated as might be the case if the system MOD changes. In addition, second order sensitivities would require three points on the CCT/power curve to be calculated before the approximation to the curve may be found. First order sensitivities only require two points on this curve to be found which is less computationally expensive.

In the author's opinion, the best method for the task of calculating generation changes is to use a 'hill-climbing' technique [74], where the size of ΔP would be limited to a maximum value for which a linear approximation is deemed sufficiently accurate or for which the maximum possible error in ΔP is acceptable. If the system is still unstable after the change in output power is implemented, a new linearisation is performed. With a stable operating point found, a binary search can be used to reach the required accuracy in ΔP using the stable and unstable values of ΔP as starting conditions. It should be noted that the discontinuity introduced when changing the number of generation units must be carefully dealt with when using a binary search technique.

The re-linearisation of the system after each change in generation also makes provision for the most stability sensitive generation unit to change. This ensures that global system generation changes are kept to a minimum. The strategy finally adopted for this work is described in more detail in section 6.8.

3.3 Factors affecting transient stability

This section covers a number of operational and design measures which may be used to improve the transient stability of the system.

3.3.1 Operational measures

3.3.1.1 Power flows

The regulation of power flows across electrically weak transmission lines is important when preserving the stability of the system. As is shown below in section 3.3.2.2, the amount of power that can be transferred across a particular system impedance limits stable operation. The nature of these limits is complex in practically sized power systems and hence they can only be determined by a large number of simulation studies. Operators therefore work with conservative estimates which are evaluated off-line.

3.3.1.2 Machine Loading

It has been shown in section 3.1.2 that part loaded generation units are more stable than fully loaded ones. System operators may therefore prefer to use more part loaded units. However, this approach may not always be compatible with economic considerations.

3.3.1.3 Voltage profile

System voltage is maintained within statutory limits by the correct regulation of reactive power sources which includes SVCs and generation units. However, it is not always beneficial to maintain nominal voltage levels in all parts of the system as this can result in generation units operating closer to their stability limits [75]. It may be better to use static compensation to achieve the required voltage levels. It should be noted though that this can increase the system's susceptibility to voltage instability by the mechanism described in section 2.4.

3.3.2 Planning and design measures

3.3.2.1 Machine parameters

High machine inertia and low transient reactance improve transient stability as they increase damping and reduce machine acceleration [48]. Unfortunately, the value of these parameters is largely the result of the size, type and construction of a machine, which in turn is usually influenced more by economic factors than stability considerations.

3.3.2.2 Transmission system reactance

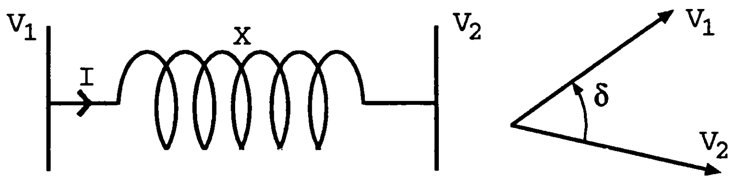


Figure 3.5: Power transfer in a lossless transmission line.

The electrical power, P_e, that may be transferred between two busbars connected by a reactance, X, is given by

$$P_e = \frac{V_1 V_2}{X} \sin\delta \tag{3.1}$$

where V_1 and V_2 are the voltages at each busbar and δ is the angle between them. Hence, the maximum power that is transferred can be increased by decreasing the value of X. This is pertinent because the 'ease' with which power is transferred around the system during a disturbance can be crucial to transient stability. Faults produce an excess of machine electrical power which is better dissipated in a system with good power transfer capabilities.

Large transmission system reactances also require machines to run at high load angles to achieve the required power transfer capability. This reduces the transient stability margin of machines.

3.3.2.3 Series compensation

Capacitor banks can be placed in series with long transmission lines to offset the line transfer reactance. One problem with these schemes is the overvoltage protective removal of the capacitors during fault conditions. Rapid re-insertion after fault clearing is needed if the transient performance of the system is to benefit from series compensation [76, 77].

3.3.2.4 Voltage compensators

Switched capacitor banks, synchronous compensators and static VAr compensators can be used to maintain system voltage. Again, this increases the power transfer capability of the system, and can help to maintain synchronism under fault conditions. However, much can depend on load characteristics and the position of compensators in the system. Under certain conditions, voltage compensation can actually degrade the transient performance of the system.

3.3.2.5 Fast valving

Fast valving is used to rapidly reduce machine prime mover input power on detection of system fault conditions. This in turn reduces machine acceleration. There are a number of different methods employed for doing this which involve regulation of the governor interceptor and/or control valves [78]. Certain utilities prefer not to use this technique to aid transient stability due to concerns that it may cause turbine damage.

Another advantage of fast valving is that it can be configured to temporarily reduce the post-fault level of prime mover input power. This temporary reduction can provide 'breathing space' during which tripped plant may be reconnected to the system.

3.3.2.6 Fast excitation systems

During power system faults, machine internal voltages become depressed which limits the synchronising power of the machine. It is therefore beneficial to try and maintain the machine internal voltage at as higher level as possible. This is best achieved using a high ceiling fast excitation system or AVR [79]. Unfortunately, such AVRs have a negative effect on the damping of local plant modes and steady-state stability. This problem is overcome by using a power system stabiliser (PSS) which often utilises a machine acceleration signal to provide additional excitation control [6,47]. In general, this type of AVR is considered as one of the best methods for improving system transient stability performance.

3.3.2.7 Load shedding

Although unpopular in some countries, load shedding can provide a convenient means of matching load to generation during onerous fault sequences such as the sudden loss of generating capacity [47]. This helps to prevent rapid deceleration of machines which can lead to instability and system splits [80].

3.3.2.8 High Voltage DC links

DC links between two strongly meshed parts of a power system, or between two power systems, can avoid the problems associated with weak synchronous interconnections. Alternatively, the current order at the rectifier and/or the voltage order at the inverter can be modulated to help damp out power system oscillations [81,82].

3.3.2.9 Fast protection schemes

Fast protection schemes are often deployed in areas where rapid fault clearing can prevent stability problems. The disturbance to the system, which is proportional to the fault duration, is thereby minimised. On the NGC system, faults are normally cleared within four or five cycles. In certain countries, where the structure of the system is 'weaker' and more radial, it is necessary to use even faster protection coupled with single pole tripping schemes [83]. Re-closing the breakers on tripped plant as soon as possible after the fault has been cleared also helps to maintain stability and reduces the system's vulnerability to further faults.

Chapter Four

Review of Classical Quantitative Stability Methods

4.1 Introduction

The transient stability of a large power system can be assessed by modelling the effects of a given set of disturbances using a computer simulation program. Time domain simulation provides the most accurate results as it has the capability to fully represent the equations describing the power system. A step-by-step solution method is used to calculate the time histories of each state variable in the system at discrete intervals. However, there are two major drawbacks with the time domain solution method.

- Time domain simulation is only able to provide a 'yes/no' answer, i.e. it can only determine whether the system is stable for a given scenario and disturbance. It is not able to provide a measure of how close the system is to a stability boundary, or provide useful sensitivity information.
- Time domain simulation is computationally intensive and consequently slow in terms of program execution time.

For the work described in this thesis, it is necessary to be able to answer questions such as *'given that the system is unstable, how can stability be restored making only the smallest changes to the active generation pattern?'*. Now, if only small changes are required, say at one generation unit, time domain simulation could be used to test system stability with the output of each generation unit reduced in turn. The best unit to choose is thus the unit for which the smallest change in active output yields a stable system. However, it is not difficult to envisage a situation where the constraint of one generation unit alone is not sufficient to restore stability. Even if only two units are needed, the total number of simulations that must be performed is vastly increased because each unit in the system must be tested with every other.

Quantitative stability methods aid this problem significantly by providing a measure of system stability, a *stability margin*. This can be used to derive sensitivity information, allowing all generation units to be ranked by their ability to affect the stability of the system. The subject of this chapter is the *direct methods* classically used to calculate stability margins.

Direct methods were originally conceived to solve the transient stability problem without explicitly solving the system equations, thereby gaining significant reductions in computational effort. However, now that cheap powerful computers are readily available and, since the numerical methods required to yield the best accuracy from direct methods are slow [84], the main benefit of direct methods should be seen as finding the stability margin.

This chapter describes the main developments in the history of the two main direct methods, transient energy function and equal area criterion. In addition, a complementary method, called *composite electromechanical distance* is mentioned. The very important topic of hybrid simulation is also covered. This attempts to couple the modelling capabilities of time simulation with the stability margin given by the transient energy function.

4.2 Formulation of system equations

To aid the description of the transient energy function and equal area criterion, it is convenient to refer all machine quantities to a system reference. The *centre of inertia* (COI) or *centre of angle* (COA) reference frame is most commonly used. This defines the *weighted mean rotor*, δ_0, system angular frequency, ω_0, and system angular acceleration, $\dot{\omega}_0$, as follows:-

$$\delta_0 = \frac{1}{M_T}\sum_{i=1}^{n} M_i\delta_i \tag{4.1}$$

$$\omega_0 = \frac{1}{M_T}\sum_{i=1}^{n} M_i\omega_i \tag{4.2}$$

$$\dot{\omega}_0 = \frac{1}{M_T}\sum_{i=1}^{n} M_i\dot{\omega}_i \tag{4.3}$$

where $M_i, \delta_i, \omega_i, \dot{\omega}_i$ are the inertia, rotor angle, angular frequency, and angular acceleration of machine i respectively. M_T is the sum of the inertias for all the machines in the system. n is the number of machines in the system.

Thus, with respect to the centre of inertia, the rotor angle, frequency and acceleration of each machine may be written

$$\theta_i = \delta_i - \delta_0 \tag{4.4}$$

$$\tilde{\omega}_i = \dot{\theta}_i = \omega_i - \omega_0 \tag{4.5}$$

$$\dot{\tilde{\omega}}_i = \dot{\omega}_i - \dot{\omega}_0 \tag{4.6}$$

Similarly, the swing equation for the classical machine model, derived in appendix E becomes

$$M_i\dot{\tilde{\omega}}_i = P_{mi} - P_{ei} - \frac{M_i}{M_T}P_{COI} \tag{4.7}$$

where

$$P_{COI} = M_T\dot{\omega}_0 = \sum_{i=1}^{n}(P_{mi} - P_{ei}). \tag{4.8}$$

4.3 The Transient Energy Function

The transient energy function (TEF) is a direct method which can be used to determine system transient stability. The stability margin associated with the TEF is known as the transient energy margin which provides information about the system's proximity to transient instability.

The TEF is a specific case of the Lyapunov direct or *second* method [85]. The principle of the TEF is related in detail to Lyapunov's method in reference [73].

4.3.1 Principle of the transient energy function

The TEF approach is analogous to a ball rolling on the inside of a bounded concave surface, as shown in figure 4.1. The surface represents the region of stability. If the ball escapes the surface it enters the region of instability. The bounding surface is uneven, so that different points on the surface are at different heights and distances from the lowest point.

In steady state the ball rests at the lowest point on the surface, known as the *stable equilibrium point* (SEP). When the ball is subjected to some disturbance, it gains kinetic energy, moving it across and up the surface in a direction determined by its initial motion and the contours of the surface. The height and distance the ball travels on the surface is governed by the amount of kinetic energy imparted to the ball. At its highest point on the surface, all the ball's kinetic energy is converted

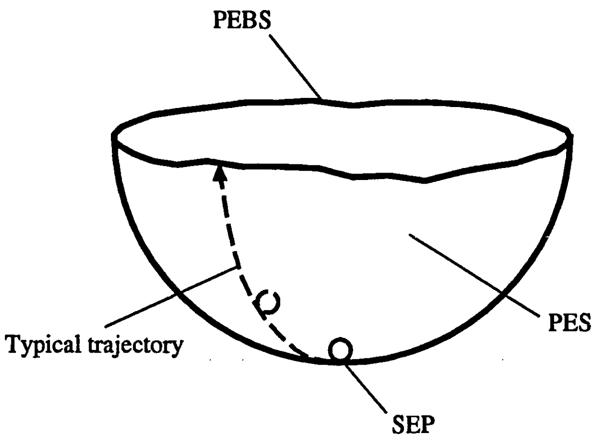


Figure 4.1: The potential energy surface

into potential energy. Subsequently, the ball will roll down the surface, eventually coming to rest back at the stable equilibrium point. If the ball is given sufficient kinetic energy initially, it will escape the bounding surface and move into the area outside the bowl, i.e. the region of instability. It is then unable to return to the stable equilibrium point.

The surface is known as the *potential energy surface* and the lip is the *potential energy boundary surface* (PEBS). To determine if the system is stable for a given disturbance, the amount of kinetic energy imparted to the ball must be known, as well as the contours of the potential energy surface and the initial trajectory of the ball.

4.3.2 The TEF and power systems

During fault conditions, the synchronous machines in a power network accelerate, gaining kinetic and potential energy. When the fault is cleared, the system settles down to a new stable equilibrium point, the kinetic energy being converted to electrical potential energy. For the system to be stable, the post fault system must be capable of absorbing all the kinetic energy in the system at fault clearing time.

Consider a fault on a power system which is cleared with *critical* clearing time t_c such that the vector of rotor angles at time t_c is described by $\underline{\delta}_c$. The rotor angles of the machines will swing to their maximum positions, denoted by the vector $\underline{\delta}_u$, at which point, all the kinetic energy in the system has been converted to potential energy. This is equivalent to a point on the PEBS, or the lip of the bowl. If the system is to remain stable, rotor oscillations should be less than $\underline{\delta}_u$. In general then, for stability, it can be written

$$PE(\underline{\delta}_c) + KE(\underline{\delta}_c) \leq PE(\underline{\delta}_u). \tag{4.9}$$

$PE(\underline{\delta}_u)$ is referred to as the *critical energy*, V_{cr}.

4.3.3 Transient stability margin

For a particular disturbance there is a corresponding post fault stable equilibrium point. In general, the post fault stable equilibrium point will differ from the pre fault stable equilibrium point because the system state will change pre to post fault. This is not only as a result of changes to the network, such as transmission lines being tripped out, but also because of the dynamic response of plant control systems.

Provided the state of the system at fault clearing, $\underline{x}_{cl}$, is inside a region of attraction to the post fault stable equilibrium point, the system will be stable for the post fault condition. The application of Lyapunov's second method allows the system to be described by the transient energy function, $V(\underline{x}_{cl})$. If $V(\underline{x}_{cl})$ is less than the critical energy of the post fault system, V_{cr}, then the system will be stable. The *transient energy margin* (TEM), V_{TEM}, is defined as

$$V_{TEM} = V_{cr} - V(\underline{x}_{cl}) \tag{4.10}$$

and gives a useful measure of system stability. Clearly, V_{TEM} is negative for an unstable fault, positive for a stable fault and zero for a critically stable fault.

In order to calculate V_{TEM}, it is necessary to find the system transient and critical energies. Calculation of the transient energy is performed using a standard method. There are several methods presented in the literature to find the system critical energy, but the reliability and speed of these different methods varies considerably. The following sections describe how transient energy is calculated and then go on to look at the various methods for finding the system critical energy.

4.3.4 Transient energy

The total transient energy is found by summating the energy of all the individual machines in the system. The energy for each machine is broken down into kinetic and potential components and is given below in terms of the system dynamic equations.

4.3.4.1 Potential energy

The transient potential energy of machine i is defined as

$$V_{PEi} = -\int_{\theta_i^s}^{\theta_i} (P_{mi} - P_{ei} - \frac{M_i}{M_T} P_{COI}) d\theta_i \tag{4.11}$$

where θ_i^s is the post fault steady state value of θ_i, i.e. θ_i at the post fault stable equilibrium point. The electrical potential energy component of V_{PEi} is referred to the *post fault* system. This is achieved by using the machine current injections superimposed on the post fault network state to calculate the machine terminal voltages and powers. It is necessary to do this because it is the potential energy absorbing capability of the post fault system which determines the critical energy [86].

Evaluation of V_{PEi}

The integral used to calculate the electrical potential energy component of V_{PEi} is not path independent unless the network admittance matrix is symmetrical and transfer conductances are ignored. Hence, to solve the integral for practical systems, it is necessary to assume a linear path in the rotor angle space between two equilibrium points [87]. The validity of this assumption is dependant on the power system being studied and the severity and location of the fault.

For hybrid transient energy function methods, described later in section 4.4, it is important to be able to evaluate equation 4.11 within the framework of a time domain integration algorithm. Performing the integration with respect to θ can introduce numerical inaccuracies. The solution to this problem is to formulate the following integral with respect to time, as proposed in reference [26]:-

$$V_{PEi} = -\int_{t^s}^{t}[(P_{mi} - P_{ei} - \frac{M_i}{M_T}P_{COI})\frac{d\theta_i}{dt}]dt \tag{4.12}$$

This equation can easily be evaluated by appreciating that $\frac{d\theta_i}{dt} = \tilde{\omega}_i$.

4.3.4.2 Kinetic Energy

The transient kinetic energy of machine i is simply defined as follows:-

$$V_{KEi} = \frac{1}{2}M_i\tilde{\omega}_i^2 \tag{4.13}$$

4.3.4.3 Total Transient Energy

The transient energy function (TEF) is defined as

$$V = V_{KE} + V_{PE} \tag{4.14}$$

and

$$V_{KE} = \sum_{i=1}^{n} V_{KEi}, \quad V_{PE} = \sum_{i=1}^{n} V_{PEi}$$

4.3.4.4 System corrected kinetic energy

Fouad and Vittal explain in [88] that, in a multi-machine power system, only a portion of the total transient kinetic energy is responsible for the system losing synchronism. The remainder is simply energy that is exchanged between stable oscillatory modes as a result of the disturbance. This energy should not be taken into account when calculating the stability margin. The system kinetic energy should therefore be corrected to take this into account. To do this the system *mode of disturbance* (MOD) must be correctly found. This topic is discussed in detail in section 4.3.5.2. Provided this is the case, V_{KE} is determined as follows:-

$$V_{KE} = \frac{1}{2} M_{eq} \omega_{eq}^2 \tag{4.15}$$

where

$$M_{eq} = \frac{M_{MOD} M_{sys}}{M_{MOD} + M_{sys}}, \quad \omega_{eq} = (\omega_{MOD} - \omega_{sys})$$

and

$$M_{MOD} = \sum_{i=1}^{n_{MOD}} M_i, \quad M_{sys} = \sum_{i=1}^{n_{sys}} M_i$$

and

$$\omega_{MOD} = \frac{\sum_{i=1}^{n_{MOD}} M_i \omega_i}{M_{MOD}}, \quad \omega_{sys} = \frac{\sum_{i=1}^{n_{sys}} M_i \omega_i}{M_{sys}}.$$

n_{MOD} is the number of machines in the mode of disturbance and n_{sys} is the number of remaining machines in the system.

4.3.5 Critical Energy

Finding the critical energy is the most difficult stage of evaluating the transient energy margin. Using the rolling ball analogy again, it is equivalent to trying to find the boundary of the concave surface by performing experiments with the ball to see if it leaves the surface given a certain initial motion. Four main approaches exist which are described below.

4.3.5.1 Closest unstable equilibrium point

Any point on the PEBS is known as an unstable equilibrium point (UEP) because the potential energy in the system is equal to the critical energy. The closest unstable equilibrium point method attempts to find the unstable equilibrium point on the PEBS which has the lowest corresponding value of potential energy. This is achieved by finding the unstable equilibrium point for all conceivable values of $\underline{\delta}_u$. The critical energy, V_{cr} is taken as the minimum value of potential energy calculated from every value of $\underline{\delta}_u$.

The problem with this method is that it assumes the worst possible post fault trajectory of the system because the value of $\underline{\delta}_u$ chosen corresponds to the unstable equilibrium point on the PEBS with the lowest energy. In other words, the ball escapes the surface by the lowest point on the boundary. This will rarely be the case in practice and consequently the transient energy margin found using this method will be conservatively low.

Another problem with this method is the large number of possible unstable equilibrium points for even a relatively small system. For an n machine system there are $2^n - 1$ possible unstable equilibrium points. This has obvious implications on the computational burden posed by this method.

4.3.5.2 Controlling unstable equilibrium point

This method aims to reduce the conservativeness of the closest unstable equilibrium point approach. To do this, the actual or *controlling* unstable equilibrium point for the given disturbance is found using a suitable numerical method. Locating the controlling unstable equilibrium point is set up as an minimisation problem in terms of the system machine swing equations which are then solved numerically [87]. The trajectory described by the system mode of disturbance is used to find an approximation to the controlling unstable equilibrium point which serves as an initial condition for the numerical minimisation.

There are two main problems with the controlling unstable equilibrium point approach:-

① The numerical minimisation problem is prone to non-convergence, or convergence to the wrong controlling unstable equilibrium point.

② Numerical solution becomes more difficult if complex machine and control system models are incorporated into the system dynamic equations.

Ejebe et al suggest in reference [89] that a large factor in the poor convergence properties of this method is the use of a centre of angle. With a load bus used as the system angle reference and a sparse formulation routine [90], the authors claim that the unstable equilibrium point has been found robustly in all test cases.

Finding the mode of disturbance

The mode of disturbance for a specified fault is the set of machines in the system which tend to lose synchronism at the unstable equilibrium point. They can be identified by performing a time domain simulation to see which machines go unstable [47]. However, this procedure is computationally intensive and therefore several other techniques are proposed in the literature. Early approaches are based on rotor angle extrapolations, either assuming constant acceleration or using sinusoidal functions to approximate the motion of each machine [87]. An alternative approach is suggested by Fouad et al in reference [91] based on normalised potential energy, but this approach is computationally intensive, especially when used with complex machine models. More recently, Machias et al propose the use of fuzzy membership functions based on rotor angles and accelerations [92].

4.3.5.3 Boundary of stability-region-based controlling unstable equilibrium point (BCU)

The basis of the BCU method is a set of *gradient dynamical equations* which can be used to 'map out' the PEBS given a single point upon it [93]. These equations can be integrated to find a point of minimum gradient. This is then used as a starting point for the controlling unstable equilibrium point solution which is performed in the manner described above. This method is considered more reliable for finding an initial guess for the controlling unstable equilibrium point than the mode of disturbance methods. In turn, the method achieves better convergence characteristics.

The problem is to find a starting point on the PEBS which is close to the point of minimum gradient. This is done by simulating a sustained fault in the time domain until the vector of rotor angles crosses the PEBS. The crossing point is called the *exit* *point*, as shown in figure 4.2. Ideally, if the exit point lies exactly on the PEBS, the minimum gradient will be zero, indicating that the controlling unstable equilibrium point has actually been reached. However, in practice, the exit point calculated from the time domain method will not lie exactly on the PEBS, and therefore the minimum gradient reached will be non-zero. Calculation of the unstable equilibrium point then proceeds as normal with the minimum gradient point as an initial condition.

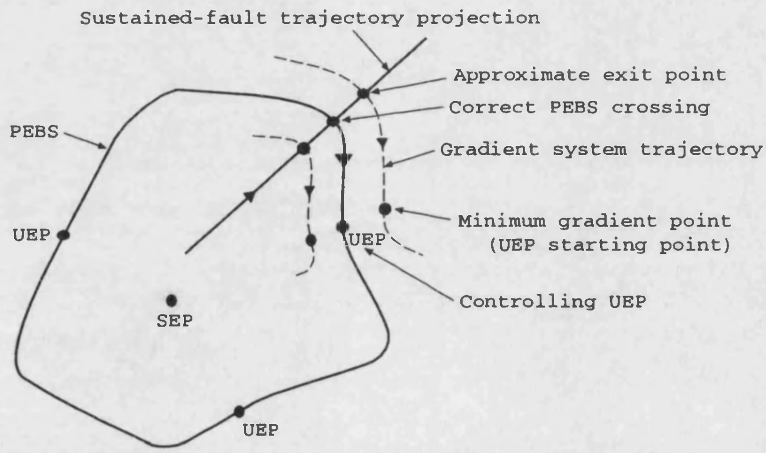


Figure 4.2: Illustration of the use of the exit point method to find the controlling unstable equilibrium point, taken from [1].

Note that the gradient dynamical equations are derived from the power system models and hence become correspondingly more involved as complex power system components are included. This has implications on the computational burden associated with this technique and also the nature of the PEBS.

4.3.6 Limitations of the transient energy function

The TEF is probably the most promising of the direct methods. However, research so far has failed to realise the its full potential. The main problem is the determination of the system critical energy. In order to gain sufficient accuracy, computationally intensive direct methods must be used. These are prone to non-convergence, or convergence to the wrong unstable equilibrium point. The latter can give misleading results.

Another major problem with the TEF method is the difficulty of including complex power system models. When it is feasible, the computational overhead is significantly increased. Solution of the path dependant part of equation 4.11 also has implications on the overall accuracy of the TEF method if system transfer conductances and phase shifting transformers are to be modelled.

4.4 Hybrid transient energy function methods

The conception of hybrid methods was inspired by the wish to combine the modelling capabilities of time domain simulation with the quantitative stability margin yielded by direct methods. The availability of low cost high power computing equipment has also meant that time domain simulation is now far more practical for both planning and operational studies. Also, as has been discussed, the solution techniques required to gain sufficient accuracy with direct methods tend to weigh heavily against their conceptual elegance and anticipated speed.

In reference [84], a CIGRE report, the authors perform a comprehensive comparison between direct and time domain methods. They state that, on average, gains in computing time when performing a task such as critical clearing time evaluation are of the order of two to four. In some cases, gains as much as 25 may be possible. The authors also point out that the use of higher order machine and control system models reduces the computational gains.

However, direct methods provide sensitivity information which is of particular relevance to the work presented in this thesis. Hence the combination of the extra information provided by direct methods and the modelling capabilities of time domain simulation is an attractive proposition.

All hybrid methods use the transient energy function to provide a stability index. Three distinct approaches are discussed in the literature. These are described below.

4.4.1 General method

All hybrid transient energy function methods calculate the system potential and kinetic energies directly from the time domain simulation machine trajectories. The various hybrid methods differ in the way in which the transient energy margin is calculated, and in particular the technique used to locate the PEBS for stable faults.

Consider a simple power system fault such that the post fault stable equilibrium point is the same as the pre fault stable equilibrium point. Depending on how rapidly the fault is cleared, the system trajectory is stable, marginally stable, or unstable. These trajectories can be projected onto the potential energy surface, which is seen from above in figure 4.3. Now consider how the transient energy margin should be calculated in the stable and unstable cases.

- **Unstable case:** It should be recalled form section 4.3.3, that the transient energy margin, $V_{TEM} = V_{cr} - V(\underline{x}_{cl})$. However, $V(\underline{x}_{cl}) = V_{PE} + V_{KE}$. Now when the system trajectory crosses the potential energy boundary surface, all the system's potential energy storage capability is used up. Hence, $V_{cr} = V_{PE}$ and $V_{TEM} = -V_{KE}$. In other words, the transient energy margin is calculated as the negative value of the system's kinetic energy as the system crosses the PEBS. This crossing can be identified by the peak in the system potential energy prior to the system becoming unstable.

- **Stable case:** Calculation of the energy margin in stable cases is more difficult. Referring to figure 4.3, the transient energy margin is the difference between the potential energy for the stable case at point A, and the marginally stable case at point B. However, since the system only reaches point A for a stable case, the distance between A and B cannot be found directly from the time domain simulation. Other methods must be used. These are described below.

4.4.2 Finding the transient energy margin for stable cases

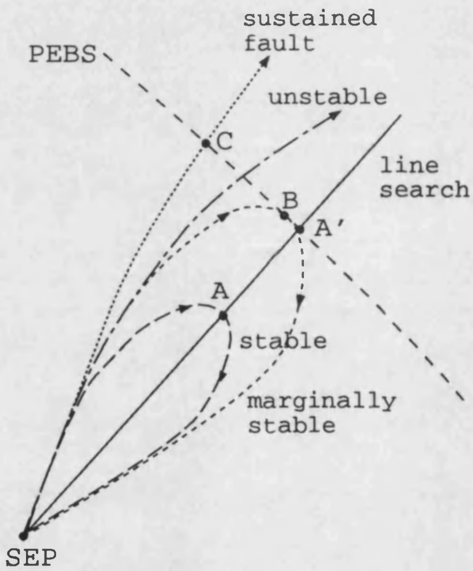


Figure 4.3: Fault trajectories in the angle space for different fault types, adapted from [2].

4.4.2.1 Line search [2]

A search for the PEBS is performed along a line from the stable equilibrium point passing through the potential energy peak point of the stable trajectory, shown as point A in figure 4.3. The PEBS crossing, point A', is found by searching for a minima in the unstable equilibrium point describing equations which in turn are calculated from the projected rotor angles on the potential energy surface. Generally, classical machine models are used for this search, tending to result in a conservative energy margin.

A second problem with this method is that the intersection between the line and the PEBS, point A', is only an approximation to the unstable equilibrium point for the marginally stable fault. The assumption is made that the PEBS is non-complex in nature, and that the mode of disturbance for the stable and marginally stable faults are the same.

4.4.2.2 Sustained fault and fault re-insertion [94, 95]

The basic principle is to apply a fault to the system which pushes it over the PEBS. The transient energy margin is then calculated as the difference between the PEBS crossing and the potential energy peak for the stable fault trajectory. The simplest way to achieve this is by applying a sustained fault to the system until the PEBS crossing is reached, shown as point C in figure 4.3. The PEBS crossing is detected as a potential energy peak.

The energy margins obtained with this method tend to be very conservative because the sustained fault is so severe that generator internal voltages are unrealistically suppressed, particularly for complex excitation system models. This conclusion leads Tang et al to suggest the use of a 'pseudo-sustained fault' in reference [96]. This fault is applied at the potential energy peak of the original fault. The method generally gives a considerable improvement in energy margin evaluation for stable cases, but the energy margin will still tend to be conservative. A second problem with this method is that in some extreme cases (e.g. a high impedance fault), an equilibrium condition can be reached whereby the pseudo-sustained fault is unable to push the system to the PEBS, i.e. the secondary fault trajectory is stable.

A subtle variation on the pseudo-sustained fault method is the 'second-kick' method reported in reference [26]. Again a second fault is applied to the system at the potential energy peak of the first. This fault should be long enough to ensure that the system crosses the PEBS. The advantage of this method is that the PEBS is crossed more reliably than when using the pseudo-sustained fault. However, for very stable cases, the method suffers from the same problems as the pseudo-sustained fault approach.

A method is proposed by Ejebe et al in reference [31] which is worth mention here too. A transient energy *index* is defined for stable cases as the first positive maximum of potential less kinetic energy after the change in sign of a special dot product, *spdtheta*. This is defined as

$$spdtheta = \sum_{i=1}^{n_g} \tilde{\omega}_i.(\theta_i - \theta_{i_{cl}}) \tag{4.16}$$

where $\theta_{i_{cl}}$ is the rotor angle of the ith machine at fault clearing.

Although the method is strongly based on hybrid TEF, the transient energy index given is not actually the same as the transient energy margin. However, this transient energy index does reduce to zero for a marginally stable system. In unstable cases the transient energy index is simply defined as the negative value of the kinetic energy as with the other hybrid methods described here.

4.5 Equal Area Criterion

The equal area criterion (EAC) can be used to determine if a one machine infinite bus system is stable when disturbed, without using the swing equation explicitly. The technique has been applied to determine the stability of large systems by first making a reduction to an equivalent two machine system. The two machines represent the *critical cluster* and the rest of the system. This system is then further reduced to a one machine infinite bus system, from which the system stability may be determined. The critical clearing time for the system can also be found.

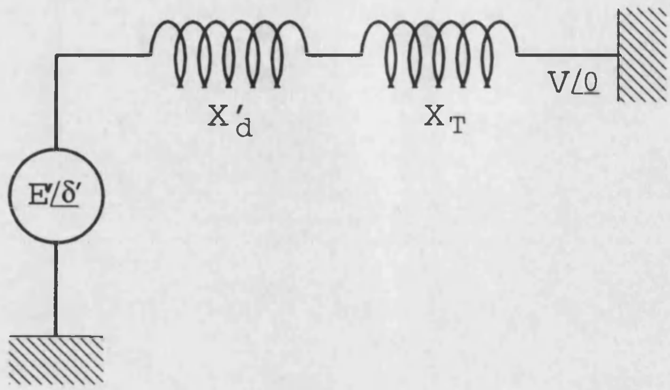


Figure 4.4: Single machine connected to an infinite busbar through a transfer impedance, X_T.

To understand the essence of the equal area criterion, it is best to examine a trivial example. Consider a single machine connected to an infinite busbar via a reactance X_T. In transient mode, the machine can be represented as a voltage, E', behind transient reactance, X'_d [97], as shown in figure 4.4. E' is at an angle δ' to the infinite bus which has a voltage V. The mechanical input power to the machine is P_m, which in steady state is converted to an electrical output power of P_e. P_e is related to the load angle as follows:-

$$P_e = \frac{E'V}{X'_d + X_e} sin\delta' \qquad (4.17)$$

During steady state operation, the mechanical input power to the machine is P_m and the load angle is δ'_0, shown as point a in the electrical power/load angle curve of figure 4.5. Suppose that the mechanical power input to the machine is suddenly increased to $\overline{P_m}$. The machine will be accelerated by the resulting imbalance between P_m and P_e according to the swing equation (E.9). The rotor of the machine will accelerate until point b where δ' satisfies equation 4.17 for $P_e = \overline{P_m}$. Now the speed of the rotor is greater than system synchronous speed, so δ' continues to increase

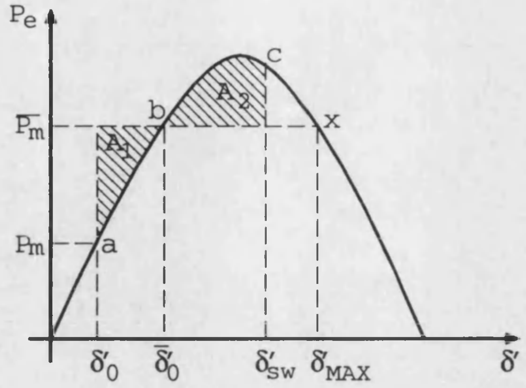


Figure 4.5: An example of the equal area criterion applied to an increase in machine output power.

until the rotor is at synchronous speed, where $\delta' = \delta'_{sw}$ (point c). P_m is now less than P_e, so the machine will decelerate and δ' will begin to decrease.

If there is no damping in the system, the rotor will oscillate about $\delta' = \overline{\delta'_0}$ indefinitely. More realistically, network resistances and machine friction will provide damping and therefore δ' will converge to $\overline{\delta'}$.

The equal area criterion is formulated by equating the kinetic energy gained by the machine rotor as it accelerates form point a to b with the energy which is then given up to the network as the machine decelerates from point b to point c. These energies can be found by assuming that the machine is operating close enough to synchronous speed at all times, such that $T_a \simeq P_a$ and thus calculating the work done. Hence, the work done, ΔW in moving from point a to b can be evaluated as

$$\Delta W = \int_{\delta'}^{\overline{\delta'}} P_a d\delta' \tag{4.18}$$

From figure 4.5 it can be seen that this integral is equal to area A_1. Similarly, the energy given up to the network is given by the area A_2.

4.5.1 Condition for stability

By finding area A_1, it is possible to determine δ'_{sw} by inserting an equal area above $\overline{P_m}$ and below the P_e/δ' curve. This is shown on figure 4.5 as area A_2. If area A_2 cannot be accommodated above $\overline{P_m}$ and under the curve, the system will be unstable because the machine rotor will swing beyond the point at which $P_e = \overline{P_m}$, marked as point x in figure 4.5. In other words, δ' will continue to increase in order to dissipate all rotor kinetic energy to the network. However, this is not possible because P_e is now decreasing with increase in δ', so the machine continues to be accelerated resulting in instability.

4.5.1.1 Stability index

A stability index can be defined by using the regions in figure 4.5. Area A_1 is renamed as A_{acc}, the work done in accelerating the machine. The entire area above P_m and under the P_e/δ' curve is defined as the maximum energy that can be stored by the system as the machine decelerates, A_{dec}. The stability index, η, is defined to be,

$$\eta = A_{dec} - A_{acc} \tag{4.19}$$

Clearly, η will be positive for a stable fault, negative for an unstable fault, and zero for a critically stable fault.

4.5.2 System fault conditions

The equal area criterion can be applied to find the maximum rotor swing for a system fault simply by using power/load angle curves which are appropriate for the transfer impedances of the faulted system. Consider a system with transfer impedance, X_{T1} and power/load angle curve $P_{e_{T1}}$ which is shown in figure 4.6. A fault is applied to

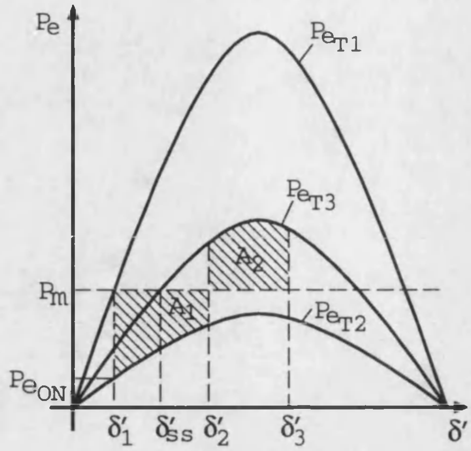


Figure 4.6: An example of the equal area criterion applied to a system fault.

the system which changes the transfer impedance to X_{T2}. Finally, the fault is cleared such that the transfer impedance is now X_{T3}. The corresponding power/load angle curves are $P_{e_{T2}}$ and $P_{e_{T3}}$ respectively.

The initial load angle of the machine is δ'_1. When the fault is applied, the electrical power that the system can absorb is $P_{e_{ON}}$. This is considerably less than the mechanical power input to the machine, P_m, so the rotor accelerates until it reaches δ'_2. At this point the fault is cleared. The kinetic energy imparted to the machine rotor is given by area A_1 and must be absorbed by the system. The post fault curve P_{T3} is now appropriate. For stability, area A_2 must fit above P_m and below the curve P_{T3}. Note that the value of electrical power that the system can now transfer is above P_m at the current rotor angle. Thus, the rotor angle will ultimately settle to δ'_{ss}.

Although the equal area criterion can be used to find the maximum stable swing of δ', it cannot be directly used to find the fault critical clearing time, which is often of more interest as it can be compared with the protection equipment clearing time. To do this, a high-order Taylor series approximation is used to describe the machine trajectory and determine the critically cleared rotor angle [98],

$$\delta'_c = \delta'_1 + \frac{1}{2}\gamma t_c^2 + \frac{1}{24}\ddot{\gamma} t_c^4 + \dots \tag{4.20}$$

where γ is the second derivative of δ' found momentarily after fault inception. This equation can be solved analytically for t_c [48].

4.5.3 The extended equal area criterion

The extended equal area criterion (EEAC) provides a means for determining the stability of any multi-machine system by reducing it to a one machine infinite bus system. This is done in the following steps:-

① For a given contingency, decompose the power system into two groups of machines. One group should consist of the *critical cluster*, while the second consists of the remaining machines.

② The two groups of machines are reduced into two single equivalent machines with appropriate parameters and rotor angles.

③ Further reduce the two groups into a one machine infinite bus system. The angle, δ' of the single machine will be the difference between the centre of angle of the two machine groups.

The parameters of the one machine infinite bus system must be found for all network conditions in the fault sequence. From this point, the system stability index may be determined as well as the critical clearing time. The method for doing this is the same as for the one machine infinite bus system.

4.5.4 Finding the critical cluster

The critical cluster is the group of machines in the system which tend to cause a loss of synchronism. Identifying the correct critical cluster is the most challenging problem when applying the equal area criterion method to multi-machine power systems. Selection of the critical cluster from a set of possible or 'candidate' critical clusters is indicated by the critical clearing time for the contingency attaining a minimum value.

Two main methods are proposed by Xue et al in the literature [98, 99] for finding the critical cluster. The major difference between these two methods is the selection of the candidate critical clusters. The early method described in [98] adopts a 'brute force' approach: A set of n_c machines are identified as potentially belonging to the critical cluster. A subset of the n_c machines are then combined to form a candidate critical cluster. The critical clearing time is found and compared with any minimum value already calculated. Unfortunately, the number of candidate critical clusters which must be tested to find the actual critical cluster is thus $2^{n_c}-1$. The assumption is also made that n_c contains the actual critical cluster. The method used to select the machines which may belong to the candidate critical cluster is therefore also very important. The technique proposed in reference [98] uses the initial machine accelerations and the pre and post fault impedances between each machine and the fault location. The method is restrictively slow for $n_c > 10$ [48].

Critical machine ranking is a more effective method for identifying the critical cluster and is described in reference [99]. Critical machine ranking avoids the need for the exhaustive search described above. This is achieved by ranking the machines in the system in the order which they should be combined. The number of machines in the critical cluster is then found by calculating the critical clearing time for each candidate critical cluster. The actual critical cluster is again identified as the candidate critical cluster yielding the shortest critical clearing time.

4.5.5 Dynamic extended equal area criterion

The extended equal area criterion described above is often referred to as the *static* extended equal area criterion because the rotor angles of the machines in the critical cluster and the remainder of the system are 'frozen' when the one machine infinite bus parameters are formulated. This can result in quite large errors during the analysis of severe contingencies. To remedy this problem, the *dynamic* extended equal area criterion (DEEAC) was devised. The one machine infinite bus parameters are refreshed at a number of points, during and post fault, depending on the desired accuracy. This is done with the aid of an appropriate Taylor series expansion and a set of sensitivity coefficients. The whole technique is described in more detail in references [99] and [48].

4.5.6 Limitations of the equal area criterion

It is difficult to reduce a multi-machine system to a one machine infinite bus system while faithfully incorporating the effects of complex power system machine and control system models. Approaches to this problem are given in references [48, 100], although it is still an ongoing research topic. In particular, the differential between X_d' and X_q' will tend to 'warp' the P_e/δ' curve [101] while AVR and governor action automatically affect the machine electrical output power and mechanical input power respectively.

In situations where the system is severely disturbed, the static extended equal area criterion is error prone. This can only be overcome by using the more complex and computationally expensive dynamic extended equal area criterion. In this thesis, the interest is in stabilising an unstable system using a suitable index to choose machines at which to make generation changes. If the extended equal area criterion, or more specifically the stability index, η, was to be used to do this, it is unlikely to be sufficiently accurate without implementing the dynamic extended equal area criterion with complex models.

Another source of error in the extended equal area criterion method is the use of the Taylor series expansion to calculate the critical clearing time. Again, while techniques have been put forward to try to remedy this problem, another element of complexity is introduced to the method which further increases computational burden.

4.6 Composite Electromechanical Distance

Transient stability is generally recognised as being a localised effect. Hence it can be useful to identify the areas of a power system which are of key interest for a given contingency. These areas can be modelled in detail, while the others are reduced to equivalent models. The demarcation of these areas is performed using a composite electromechanical distance.

The composite electromechanical distance is built up from several simple electromechanical distances such as initial post fault machine acceleration, accelerating power, machine inertia and pre fault impedance. Various techniques can be employed to combine the individual electromechanical distances to form the composite electromechanical distance. These are reviewed in reference [48].

The composite electromechanical distance yields insights into the machines which are relevant to a given disturbance. This is useful when reducing the transient stability problem space. In other words, the machines which are highly involved in a particular disturbance will have low composite electromechanical distances. These can then be selected for further analysis when attempting to stabilise the system. The author has done some work on using a composite electromechanical distance based on fault interrupted power flow, presented in [102] and discussed further in section 5.2.5. In the reference, the transient energy of the machines selected by this composite electromechanical distance is used to help find suitable constraint actions.

Note that the aim of the composite electromechanical distance method should not be confused with dynamic reduction techniques which aggregate groups of *coherent* machines. The latter often reduces the machines of *most* relevance to the given disturbance. Because reduction imposes modelling constraints on the aggregated machines, accuracy can easily be sacrificed.

Chapter Five

New Quantitative Stability Method

In the previous chapter, it has been seen that the reliability, efficiency and generality of direct methods may not meet the criteria required for certain applications.

Reliability can be a problem for several reasons. Firstly, direct methods are generally only suitable for detection of first swing transient instability; a second swing unstable system may appear more stable than a system with a large first swing which is in fact stable. Secondly, the methods themselves are subject to assumptions and approximations which can lack validity in certain circumstances. Finally, some of the numerical solution techniques which are used are prone to non-convergence.

The efficiency of direct methods may be substantially reduced because of the computationally intensive numerical methods which are required to solve the stability problem for realistically sized power systems. The inclusion of complex control system models, such as fast excitation systems, again reduces the efficiency of direct methods.

Generality of direct methods refers to their ability to deal with complex power system structures and models. Even if it is possible to include complex load, machine and control system models, this can have very detrimental effects on the method's convergence characteristics and computational efficiency.

However, direct methods do provide sensitivity information without which stability restoration tasks cannot be performed in reasonable time scales.

The method presented in this chapter is effectively a subroutine of the generation constraint algorithm embedded in the CAMEL software and described in section 6.8. To meet the requirements of this algorithm, the stability analysis should rank the generation groups in the system by their ability to restore transient stability for the smallest change in active power output. In other words, it is not necessary to analyse system stability in stable cases, and also there is no need to calculate a stability margin. Instead, the only quantity of interest is the sensitivities of individual generation groups with respect to system stability.

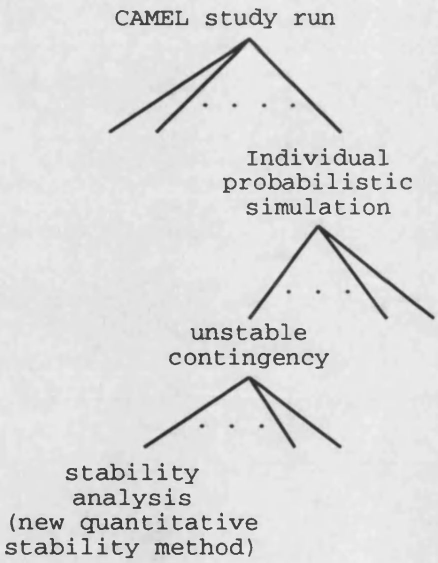


Figure 5.1: Stability analysis within the CAMEL task hierarchy

A second requirement of the method used for the work in this thesis is that it should be fast. In the event of an unstable contingency, the generation groups in the system may need to be ranked several times while finding a stable system state. Additionally, there may be several unstable contingencies in each individual probabilistic simulation. Finally, a whole CAMEL run will involve hundreds of individual probabilistic simulations. This hierarchy is illustrated in figure 5.1, while the stability analysis task is placed in context in chapter 6.

5.1 Artificial Neural Networks

The quantitative stability method described in this chapter is inspired by the application of artificial neural networks (ANNs) to the *assessment* of transient stability. Excellent results have been achieved and reported by Edwards et al [42] when applying such techniques to power systems with around 100 generation groups and 1000 busbars. The novel aspect of the work is the selection and use of a set of features of the power system which are developed from the transient behaviour of the system prior to the end of the contingency sequence, or *contingency termination point.* These features are built by taking the statistical properties of a particular variable. For example, rather than using the voltage at specific busbars in the system as features, the lowest voltage across all the busbars in the system, say, might be used. Such features are termed *composite indices.*

The advantage of using composite indices is that their application is not specific to a certain power system model or operating condition. For instance, an engineer may know that for a certain system, the voltage at a given busbar is a good indicator of the system's transient stability. The voltage at that busbar could therefore be chosen as an input to an ANN. However, given a different system or significantly changed operating point, the selection of an appropriate busbar may have to be repeated. Composite indices are less specific and therefore, if their selection is performed properly, more generic.

The work done by Edwards et al uses composite indices as inputs to an ANN and achieve a higher efficiency for performing transient screening of contingencies than that reported with the direct methods discussed in the previous chapter. Despite this performance there are a number of reasons why the ANN approach cannot be easily adapted for giving quantitative stability information. These are as follows:-

① The output of the ANN is a value between 0 and 1 which is compared with a threshold value. The network is trained using a continuously valued *severity index* which is derived from the full time domain response as follows: In stable cases, the severity index is derived from the decaying rotor oscillations by fitting an exponential to the peaks of the swing curve. The time constant of this curve can then be determined and used to form the stability index. The method for doing this is illustrated in section 2.3 and described in more detail in reference [28]. In unstable cases, the severity index is derived from the time taken for the first unstable generation group in the system to pole slip.

The problem with both of these metrics is that their relation to the true stability of the system, or energy margin, is not known. Certainly, the time taken to reach pole slip is not sufficient for quantifying system transient stability. Although both time to pole slip and oscillation decay rate prove useful for training an ANN for stability classification, there is no evidence that the output of the ANN will then correlate with system stability or energy margin.

② Ideally, if an ANN were to be used to give a quantitative stability index, it should be trained using energy margin. However, given that the methods required to measure energy margin tend to suffer with inaccuracy, an ANN so trained would probably exhibit the same characteristics.

A better solution would be to train a neural network using results from time domain simulations, such as critical clearing time. However, this would increase the number of simulations required to perform successful training by an order of magnitude. Generation of the time domain stability results required to train a network for stability assessment is already an onerous task.

③ The ANN classifier has only been proven with a power system containing relatively simple AVR and governor models and without other control systems such as SVCs. Although it is likely that selection of appropriate composite indices would enable an effective ANN to be trained, this work has yet to be carried out. It should be noted that the structure of some of the models yet to be included can introduce more complex system trajectories. This alone suggests that the task of training an effective ANN screen will be more onerous.

5.2 Composite Index Method

The method described in this chapter attempts to directly harness the power of composite indices, while negating the need for an ANN and all the associated training. The basic approach is to use the sensitivity of a select set of indices to rank the generation groups in the system. Provided the indices are chosen correctly, then a high sensitivity for each index indicates that a given generation group is highly stability sensitive. Clearly then, a set of indices must be chosen which have a high rate of change with change in the stability of the system.

As has been mentioned earlier, the only result required from the stability analysis is a 'stability rank' of all the generation groups in the system, i.e. all generation groups should be ranked according to their ability to restore system stability for the smallest change in active output power. The numerical values of index sensitivities are not actually important because they are only used to position the generation groups in a ranked list. By taking this approach, relative weighting of each of the set of indices is not necessary. Instead, each index is used to rank the generating groups by itself and then an average ranking for each generation group is found using all the selected indices.

Clearly, to obtain satisfactory results using composite indices without an ANN to perform a non-linear mapping, it will be necessary to enhance the descriptive power of the indices. To meet this requirement, the automatic identification of plant which indices are 'built' from has been extended. This is described further in section 5.2.5. The following sections describe how time domain and sensitivity analysis data are used to select an appropriate subset of composite indices from a large number of candidate indices.

5.2.1 Time domain constraint evaluation

In order to select a suitable set of composite indices it is necessary to have an ideal ranking for the generation groups in the system. Hence, every group in the system is ranked for each of a set of typical contingencies using the results of time domain simulation analysis. This analysis establishes the active power generation constraints required for each group to restore stability. The ranked lists found in this way are compared with the sensitivity of each candidate composite index. A subset is selected which is capable of performing the ranking task without the need for computationally intensive time domain simulation. The index selection procedure is described in more detail later in section 5.2.3.

The algorithm which is used to determine generation group constraints tests each group to see if it can restore system stability. If this is the case, a binary search is used to find the highest stable level of group active output, i.e. the smallest constraint consistent with stability. This procedure is described in more detail below.

For each generation group:-

① Set the output of the group to zero.

② Run a load flow and test the stability of the system using time domain simulation.

③ If the system is still unstable continue to the next generating group. If the system is stable, use a binary search to find the maximum stable output of the group. This is achieved by successively halving the difference between stable and unstable values of power output until a preset tolerance is reached. The stability of the system is determined at each iteration as in step ②. A search tolerance of 1 MW was used for this work.

There are two factors which must be considered when performing the binary search. Firstly, the generation which is constrained must be balanced by changes in generation elsewhere in the system. Two methods for doing this have been tried. Either the change in generation can be compensated for by a static load lumped at the slack bus, or it can be distributed across the other generation groups in the system. It is considered better to lump generation changes at the slack bus as this avoids altering the output of other generating groups which may cloud interpretation of results. However, it should be appreciated that load lumped at the slack bus will affect the power flows in the system, particularly in an area local to the slack bus.

The second factor to be considered is the implementation of the generation group output change. It has been noted in section 3.1.2 that changing the number of generation units when scaling the output of a group can cause a discontinuity in the stability of the system. This can cause problems with the correct convergence of a binary search technique. It is the relative stability sensitivity of each group which is of interest here and not practical constraint actions. Hence the number of generating units is not scaled for the purposes of the binary search.

It should be appreciated that the choice of appropriate composite indices is best made by comparison with a linearisation of the system at a given operating point. The evaluation of generation constraints made with the above method attempts to achieve this. Unfortunately, the size of the generation changes required during this process may occasionally shift the operating point further than the linear stability domain, particularly if the system mode of disturbance changes. However, as will be seen later, this method has produced acceptable results when selecting composite indices and it can also be run in practical time scales for large power systems (1000 busbars and 100 generation groups).

An alternative method has been tested which uses the sensitivity of critical clearing time to generation active power changes. The main problem with this approach is that a very small simulation time step must be used to gain sufficient accuracy and hence the method is very computationally intensive. Comparisons with results obtained using the generation constraint search described above gave similar results, so the critical clearing time method was abandoned. The use of critical clearing time is considered further in section 8.2.1.2.

5.2.2 Composite index sensitivity analysis

A contingency is applied to the power system and the response of the system evaluated up until the end of the contingency sequence, or *contingency termination point* (CTP), using time domain analysis. A specified set of composite indices are then calculated from the simulated states of the system.

The output of one generation group in the system is perturbed by a small amount, a load flow is run and the response of the system to the given contingency determined as before. The sensitivity of each composite index to the change in generation group output can then be calculated. The process is repeated for all generation groups in the system.

The value of the generation change used to perform the sensitivity analysis can be set to a percentage of the group's total output or a specific power. The latter option is preferable because the value of the generation change at the system's slack bus is the same for each generation group's perturbation. Also, it is a linear approximation of the system's stability which is of interest. A 10 MW step was found to be sufficient to produce useful sensitivities for this work.

5.2.3 Composite index selection

The sensitivities of each composite index are found for the perturbations of all generation groups and all contingencies. The relative sensitivity of each index for each generation group can then be used to rank the groups for each contingency. These results are then compared with the results of the time domain constraint evaluation in order to select the composite indices which are able to rank the generation groups in the same way as the time domain evaluation. An error for composite index I is thereby defined as:-

$$\varepsilon_I = \frac{1}{c.m}\sum_{i=1}^{c}\sum_{j=1}^{m}\left|R_{C_{ij}} - R_{I_{ij}}\right|^N \tag{5.1}$$

where c is the number of contingencies studied, m is the number of generation groups. $R_{C_{ij}}$ is the rank of generation group j for contingency i found using time domain constraint evaluation. $R_{I_{ij}}$ is the rank of generation group j for contingency i found using the sensitivity of index I. N is an arbitrary value which can be changed to affect the degree of penalisation for large errors in values of $R_{I_{ij}}$.

A trivial example is now given to show how the error for a composite index is found in practice. Consider the results obtained from a small system containing generation groups GEN-1 to GEN-5, as shown in table 5.1. The time domain constraint

Generation group	Active constraint (MW)	R_C	R_I
GEN-3	-14	1	1
GEN-2	-20	2	4
GEN-4	-23	3	2
GEN-1	-52	4	3
GEN-5	-89	5	5

Table 5.1: Constraint and sensitivity results used to evaluate the error term ε_I for a typical composite index.

evaluation results are shown in column 2. Column 3 shows the rank for the groups corresponding to the constraint evaluation results and column 4 shows the rank for the groups obtained by using the sensitivity of an index, I. The error for this index is thus calculated as

$$\varepsilon_I = \frac{1}{1.5}[|1-1|^N + |2-4|^N + |3-2|^N + |4-3|^N + |5-5|^N] \tag{5.2}$$

For $N = 2$, $\varepsilon_I = 1.2$. Different values of N have been experimented with to see which selects the best indices for large power systems. Large errors in single values of R_I could potentially cause severe mis-ranking of groups in the system which in turn may have large constraint cost implications. Hence it is considered best to heavily penalise large errors in single values of R_I. Using $N = 3$ has been found to achieve this is practice.

To reflect the fact that some sensitivities may be negative in value, an error term is also calculated based on the 'negative rank'. For the above example, the negative rank error would be

$$\varepsilon_{I_{NEG}} = \frac{1}{1.5}[|1-5|^N + |2-2|^N + |3-3|^N + |4-2|^N + |5-1|^N]. \tag{5.3}$$

Now with $N = 2$, $\varepsilon_{I_{NEG}} = 7.2$, so the normal ranking would actually be used for this composite index instead of the negative ranking. In a similar way, a rank and negative rank found from the inverse composite index sensitivities will be selected to rank the generation groups should this yield a smaller error.

When an error has been assigned to each composite index, the whole set is placed in a list in ascending order by error. A subset of these indices is then chosen from the top of the list to rank the generation groups in the system, such that the overall rank error is minimised. Hence, if U_I is the subset of N selected indices, then the average rank of generation group j for contingency i is found from:-

$$\bar{R}_{ij} = \frac{1}{N} \sum_{I=1}^{N} R_{I_{ij}} \tag{5.4}$$

5.2.4 Use of selected composite indices

The composite indices selected by the above process are saved to a file so that they can be used later to perform the group ranking task without the need for time domain constraint evaluation. The composite indices are simply calculated at the contingency termination point as before, and equation 5.4 is used to find the rank of each generation group in the system.

Note that the sign of the sensitivity of each index is used to determine whether decreasing the output of a generating group will have a good or bad effect on system stability. If the sensitivity of the majority of the indices is less than zero for the change in output of a group, this means that the stability of the system will increase as the group's output is reduced. The converse is also true. It is necessary to make this distinction so that only the highly stability sensitive groups which improve system stability when their output is *reduced*, are considered for *constrain-off* actions.

5.2.5 The composite indices

The indices used for ranking the generation groups are derived from the power system state. Instead of simply using raw elements of this state as indices, a dimensionality reduction is made. This is beneficial for two reasons. Firstly, it means the practical application of the method is scalable to large power systems. Secondly, it helps to ensure that the generality of the method is preserved across different system demand levels.

The indices are calculated at the contingency termination point, i.e. when all network topology changes are complete. The time domain simulation is halted at this point. Because most fault durations are of the order of hundreds of milli seconds and a full contingency simulation used for stability evaluation is generally between 5 and 12 s, the computational effort of calculating the indices is minimal.

The form of the indices is best described using set notation. Each index, I, is the intersection of six set members:-

$$I = A \wedge B \wedge C \wedge D \wedge E \tag{5.5}$$

where A, B, C, D, E are members of the sets U_a, U_b, U_c, U_d and U_e respectively.

Set U_a defines the range on the area of the power system from which the index is built. This can be *local*, *system*, *mod*, or *con*. *local* and *system* mean that the index is built from the parameters of plant local to the fault or from the whole system respectively. *mod* means that the index is built only from the parameters of the generation groups participating in the system mode of disturbance. *con* means that the index is only built from the parameters of the generation groups contributing to certain power flows in the system. These are the transmission system power flows interrupted at the onset of a contingency. A summation is made of the pre-fault power flows. The contribution to this total power flow from each generation group is then calculated using an adaptation of the algorithm described by Kirschen et al in reference [103]. The per unit contribution for each group is then given by:-

$$contribution = \frac{faulted\ power\ flow\ from\ group}{group\ output} \tag{5.6}$$

Finally, only the generation groups with a non zero contribution are used when building *con* composite indices. The value of the contribution defines the proportion of the total value of the composite index attributable to each generation group.

The*mod* and *con* plant specifiers have been added to enhance the indices' ability to 'focus' on the transient stability problem. Note that *mod* and *con* indices can only be used with the generation group member of the set U_b defined below.

Set U_b describes the type of plant from which the index is built, either busbars, generation groups, or network branches (lines and shunts).

U_c is a set of statistical functions used to reduce the values of an index over several items of plant to one single numerical value. Examples include *sum*, *average*, *rms* and *variance.* Up to twelve different functions are available.

U_d is the set of plant parameters, or *features*, used to form indices. Table 5.2 shows the parameters available for each type of plant. All parameters are processed in their appropriate per unit form.

U_e is a set of functions which describe how the index is derived from the power system measurements. This set contains three members, *change*, *ctp*, and *gradient.* *change* means that the index is found by taking the difference between the power system state at the start of the contingency and at the contingency termination

Parameter	Plant type		
	Busbar	Line	Generation group
Voltage magnitude	*	*	*
Voltage phase	*	*	*
Loading		*	*
MW		*	*
MVAr		*	*
Power factor		*	*
MVAr generated		*	
AVR voltage error			*
Rotor angle			*
Rotor speed			*
Rotor acceleration			*
Kinetic energy			*
Momentum			*
Time to pole slip			*
Accelerating power			*

Table 5.2: Table of plant parameters used to form indices. * indicates that a parameter is available for respective plant type.

point. *ctp* means that the index is given by the value of the power system state at the contingency termination point, and *gradient* means that the gradient of the power system state at the contingency termination point is used.

5.3 Results

Best results are achieved when the selection of a suitable set of composite indices is made with the same power network as CAMEL studies are to be run on. Equally the contingency set used should also be representative of the final set to be run during the CAMEL study. This ensures that the selected set of composite indices produce the best possible results over a diverse set of system demand and generation patterns.

The sample results given in this section are intended to demonstrate the potential of the composite index method. To this end, the method is compared with a state-of-the-art direct method; the hybrid transient energy function. For stable simulations, the second kick method is applied to yield an energy margin. The author believes that, of the classical direct methods, the hybrid TEF provides the best combination of accuracy and speed.

5.3.1 First swing instability

The selection of a suitable set of composite indices for first swing instability was made with the test system used for the main CAMEL results, as given in chapter 7. Base-case loading of 90% ACS was used at this stage so that the maximum set of 87 generation groups would be required to meet system demand. A select set of eight contingencies, given in appendix A, was used for index selection. At the base-case system loading level, the clearing times were set just above the critical clearing times so that all eight contingencies are first swing unstable. The rotor angle plots for the generation groups involved in the system mode of instability are shown in appendix B.

Using the technique described in this chapter, 77 composite indices were selected from a total of 2880 to give the minimum overall average error in group ranking. The select set is listed in table 5.3. Column 1 is a reference number used to refer to each index. Columns 2-6 are explained by the description of composite indices given above in section 5.2.5. Column 7 indicates how the value of the respective index should be manipulated to obtain the generation group ranking. For example, the inverse of index 41's sensitivity will be used to obtain a generation group ranking. The desired rank for generation group j is then given by $m+1-R_{I_j}$ where m is the number of generation groups in the system.

No.	Range of index	Plant type	Statistical function	Feature	Point of measurement	Ranking direction
1	SYSTEM	GROUP	MIN	ROTANG	CHANGE	neg rank
2	MOD	GROUP	MAX	VP	CTP	rank
3	SYSTEM	GROUP	RANGE	ROTANG	CHANGE	rank
4	SYSTEM	GROUP	MIN	TTOPS	CTP	neg rank
5	SYSTEM	GROUP	RANGE	MOMENTUM	CHANGE	rank
6	SYSTEM	LINE	VARIENCE	VARGEN	CTP	rank
7	SYSTEM	GROUP	SUMMOD	MOMENTUM	CHANGE	rank
8	SYSTEM	LINE	RMS	MVAR	CTP	rank
9	SYSTEM	LINE	VARIENCE	MVAR	CTP	rank
10	SYSTEM	LINE	STDDEV	VARGEN	CTP	rank
11	SYSTEM	LINE	STDDEV	MVAR	CTP	rank
12	SYSTEM	LINE	RMS	MVAR	CHANGE	rank
13	SYSTEM	LINE	VARIENCE	MVAR	CHANGE	rank
14	SYSTEM	LINE	STDDEV	MVAR	CHANGE	rank
15	SYSTEM	LINE	SUMMOD	VM	CTP	rank
16	SYSTEM	BUSBAR	MIN	VM	CTP	neg rank
17	SYSTEM	GROUP	SUM	KE	CHANGE	rank
18	SYSTEM	GROUP	MEAN	KE	CHANGE	rank
19	MOD	GROUP	MIN	VP	CTP	rank
20	CON	GROUP	SUM	VP	CHANGE	rank
21	CON	GROUP	MEAN	VP	CHANGE	rank
22	SYSTEM	LINE	SUMMOD	MVAR	CTP	rank
23	SYSTEM	GROUP	RANGE	ROTSPEED	CHANGE	rank
24	SYSTEM	GROUP	RMS	KE	CHANGE	rank
25	SYSTEM	GROUP	RANGE	ROTANG	GRADIENT	rank
26	SYSTEM	GROUP	RANGE	ROTSPEED	CTP	rank
27	CON	GROUP	SUM	MW	CHANGE	neg rank
28	CON	GROUP	SUM	ACCPOW	CHANGE	rank
29	LOCAL	GROUP	MIN	TTOPS	CTP	neg rank
30	SYSTEM	LINE	SUMMOD	VM	CHANGE	rank
31	SYSTEM	GROUP	VARIENCE	MVAR	CTP	rank
32	SYSTEM	GROUP	STDDEV	MOMENTUM	CTP	rank
33	SYSTEM	GROUP	RMS	MOMENTUM	CHANGE	rank
34	SYSTEM	GROUP	STDDEV	MOMENTUM	CHANGE	rank
35	SYSTEM	GROUP	RMS	MOMENTUM	CTP	rank
36	LOCAL	GROUP	RMS	ROTANG	CTP	rank
37	SYSTEM	GROUP	STDDEV	MVAR	CTP	rank
38	CON	GROUP	RMS	ROTANG	CTP	rank
39	CON	GROUP	SUM	MVA	CHANGE	neg rank
40	LOCAL	BUSBAR	MIN	VM	GRADIENT	neg rank
41	LOCAL	BUSBAR	MAX	VP	CTP	neg inv rank
42	LOCAL	GROUP	SUM	VP	CHANGE	rank
43	LOCAL	GROUP	MEAN	VP	CHANGE	rank
44	LOCAL	GROUP	SUM	VP	CTP	rank
45	LOCAL	GROUP	MEAN	VP	CTP	rank
46	LOCAL	GROUP	SUMMOD	ROTANG	CTP	rank
47	SYSTEM	LINE	RMS	VM	CTP	rank
48	CON	GROUP	STDDEV	MVAR	CHANGE	rank
49	CON	GROUP	VARIENCE	MVAR	CHANGE	rank
50	SYSTEM	LINE	VARIENCE	VM	CTP	rank
51	LOCAL	GROUP	MAX	ROTANG	CTP	rank
52	SYSTEM	LINE	SUMMOD	MVAR	CHANGE	rank
53	SYSTEM	LINE	STDDEV	VM	CTP	rank
54	MOD	GROUP	SUM	VP	CTP	rank
55	SYSTEM	LINE	MEAN	MW	GRADIENT	rank
56	SYSTEM	LINE	SUM	MW	GRADIENT	rank
57	SYSTEM	GROUP	VARIENCE	ROTANG	CHANGE	rank
58	SYSTEM	GROUP	RMS	ROTANG	CHANGE	rank
59	CON	GROUP	MEAN	MVA	CHANGE	neg rank
60	SYSTEM	GROUP	RMS	MVAR	CTP	rank
61	SYSTEM	GROUP	MEAN	MW	GRADIENT	neg rank
62	SYSTEM	GROUP	SUM	MW	GRADIENT	neg rank
63	SYSTEM	GROUP	VARIENCE	ROTANG	GRADIENT	rank
64	LOCAL	BUSBAR	SUM	VP	CTP	rank
65	LOCAL	BUSBAR	MEAN	VP	CTP	rank
66	SYSTEM	GROUP	SUMMOD	ROTANG	CHANGE	rank
67	SYSTEM	GROUP	MINMOD	VP	CTP	neg rank
68	SYSTEM	GROUP	SUMMOD	ROTSPEED	CHANGE	rank
69	SYSTEM	GROUP	SUMMOD	ROTSPEED	CTP	rank
70	SYSTEM	GROUP	SUMMOD	ROTANG	GRADIENT	rank
71	LOCAL	GROUP	RMS	MVAR	CTP	rank
72	MOD	GROUP	MAX	ROTANG	CTP	rank
73	SYSTEM	BUSBAR	MEAN	VM	GRADIENT	neg rank
74	SYSTEM	BUSBAR	SUM	VM	GRADIENT	neg rank
75	SYSTEM	GROUP	VARIENCE	ROTSPEED	CTP	rank
76	SYSTEM	GROUP	VARIENCE	ROTSPEED	CHANGE	rank
77	SYSTEM	GROUP	RMS	ROTANG	GRADIENT	rank

Table 5.3: Set of 77 composite indices selected from a total set of 2880 to perform the generation group ranking task for first swing transient instability.

The results achieved on the base-case system with the selected set of composite indices are shown in the tables in appendix B. Column 1 gives the names of the generation groups which correspond with the study file for the network used in this study. Columns 2 and 5 give the results of the time domain constraint evaluation. The data in column 5 is the actual constraints found by binary search. Column 2 is a rank for the generation groups in the system which is derived from the constraints. The rank in column 2 is the 'ideal' generation group ranking which was used to select the subset of composite indices presented in table 5.3. Column 3 gives the rank of the generation groups in the system found using only the selected set of composite indices. Note that the letter in this column indicates the generating group's effect on system stability. 'I' means that a decrease in the output of the respective group will increase the stability of the system. 'D' means that the system stability will be decreased by a decrease in output, and 'M' denotes a negligible effect on system stability.

Column 4 is the sensitivity of the transient energy margin (TEM) to changes in the output of the corresponding generation group. For instance, in table B.1, generation group CRUA81 has an energy margin sensitivity of -3.1 per 100 MW change in output. In other words, the system's energy margin increases by 3.1 per unit generation shed at generation group CRUA81.

The average error in generation group ranking in the base case using sensitivity of the TEM is **5.63**, compared with **3.23** for the composite index method. Clearly, this indicates that the generation ranking which may be achieved with the composite indices is considerably better than that achieved with TEM sensitivities.

Looking at this set of results qualitatively, it is possible to see that both methods are quite effective at identifying the generation groups capable of restoring stability and ranking them highly. There are some cases for which the TEM sensitivities gives better results than the composite indices, for example the Deeside-Trawsfynydd-Legacy contingency. Conversely, the composite indices have achieved a better ranking in other instances, for example the Cellerhead-Macclesfield-Daines contingency. Overall though, the composite indices produce a better generation group ranking.

In certain respects, it is encouraging to see that the composite indices do not rank the generation groups perfectly because that would suggest that the indices are selected to recognise a specific set of patterns rather than general trends of system stability.

It should be noted that the results from the time domain constraint analysis, against which other methods are bench-marked here, must be brought into question for three reasons.

- A generation group may be quite stability sensitive at the current operating point, but small changes in the operating point of the system will drastically reduce its sensitivity to system stability. Hence, one of the sensitivity methods presented here will rank the group highly, but a large reduction in the group's output could be necessary to restore the system stability. A possible example of this effect is the large constraints for groups LOAN81 and LOAN82 for the Harker-Hutton contingency.
- Constraints may not be found for generating groups with small power outputs. This is because the size of the constraint required is greater than the active power output of the group.
- The allocation of generation at the system's slack bus can have significant effects on the system's power flows. This can occasionally introduce new modes of instability into the system which will interfere with the interpretation of results. A possible solution is to distribute slack power amongst the generation groups in the system. However, this will result in small increments in power at other potentially stability sensitive generation and may have profound effects

on the stability.

5.3.1.1 Different operating conditions

The set of results presented above was found with the base case for which the set of composite indices was actually selected. This shows that the composite indices are able to identify trends in system stability, and therefore perform the required ranking task with greater accuracy than the TEM. However, to demonstrate a real advantage for the new method over the TEM, it is necessary to show that the selected set of composite indices is also effective for different system conditions.

To do this, three study files at different levels of loading were taken from a set of data generated by CAMEL. The system demand levels of 45, 60 and 75% ACS were chosen to cover the likely range that would be used for a comprehensive CAMEL study. Clearing times 10-15 ms greater than the critical clearing time were found and used for each contingency. These clearing times, along with those for the base case, are shown in table 5.4. The generation groups in the system were ranked using the selected set of composite indices and full time domain constraints were also evaluated. The results were then compared to give the average rank errors shown in table 5.5.

System	Contingencies						(CTs in ms)	
	Strat.	Eccl.	Hark.	Penw.	Kead.	Dees.	Cell.	Hink.
45% ACS	265	315	1280	255	455	360	435	335
60% ACS	225	265	790	230	830	320	445	255
75% ACS	210	255	685	245	590	265	535	245
90% ACS	205	240	740	280	635	280	525	250

Table 5.4: Clearing times used for the three test systems and the 90% ACS base case. The contingency sequences are fully illustrated in appendix A.

It can be seen from table 5.5 that the accuracy of the composite index ranking method tends to decrease as the system demand level deviates further from the base

System Description	45% ACS 47 gen. groups	60% ACS 61 gen. groups	75% ACS 68 gen. groups	90% ACS 87 gen. groups
Average rank error	4.85	3.59	3.98	3.23

Table 5.5: Average generation group rank errors for the three test cases and the 90% ACS base case. All contingencies first swing unstable.

case for which the indices were selected. However, even for the 45% ACS case, the average rank error is *still less* than the TEM sensitivity results for the base case. These results could be further improved on in the future by selecting indices using a broad set of operating conditions. The requirements for extending the procedure described in this chapter are laid out in section 8.2.1.

5.3.2 Subsequent swing instability and damping

Many of the generation groups in the system used above are fitted with fast excitation systems and power system stabilisers. These increase the stability of the system, making it quite robust to subsequent swing instability and damping problems. Thus, to explore the performance of the composite index method for subsequent swing instability, it was necessary to modify the system to make it less stable. This was achieved by changing the excitation systems to simple NGC 001 [40] type and removing all the power system stabilisers. Studies at different operating points were generated using CAMEL. CAMEL was also used to perform the initial stability classification so that the individual studies which were subsequent swing unstable could be identified.

The indices found for the first swing unstable cases above were used to determine the generation rank for a system for which four of the list of eight contingencies were

No.	Range of index	Plant type	Statistical function	Feature	Point of measurement	Ranking direction
1	SYSTEM	BUSBAR	MAX	VP	CTP	rank
2	SYSTEM	GROUP	MIN	ROTANG	CTP	neg inv rank
3	SYSTEM	GROUP	MINMOD	MVAR	GRADIENT	neg inv rank
4	CON	GROUP	STDDEV	VP	CTP	rank
5	SYSTEM	GROUP	SKEW	VP	CTP	rank
6	CON	GROUP	SKEW	PF	CTP	rank
7	CON	GROUP	RMS	ROTACCN	CHANGE	neg rank
8	CON	GROUP	SUMMOD	MVA	CHANGE	neg rank
9	CON	GROUP	RANGE	VP	CTP	rank
10	CON	GROUP	VARIENCE	VP	CTP	rank
11	CON	GROUP	RMS	ROTACCN	CTP	neg rank
12	CON	GROUP	MEAN	MVA	CHANGE	rank
13	CON	GROUP	SUM	MVA	CHANGE	rank
14	SYSTEM	BUSBAR	SKEW	VP	CTP	rank
15	CON	GROUP	SKEW	VP	CHANGE	neg rank
16	SYSTEM	LINE	MAXMOD	MW	GRADIENT	rank
17	SYSTEM	LINE	SUMMOD	MW	CHANGE	neg rank
18	CON	GROUP	SUM	ROTACCN	CHANGE	neg rank

Table 5.6: Set of 18 composite indices selected from a total set of 2880 to perform the generation group ranking task for subsequent swing transient instability.

subsequent swing unstable. This system is called the base case and is summarised in table 5.7. After performing the time domain constraint analysis, the average rank error for these four contingencies was found to be 23.18, indicating that the indices selected for first swing instability were not able to performing the ranking task. This is expected because first and subsequent swing instability are understood to be caused by different mechanisms, as explained in section 2.3. Thus, a different set of indices should be chosen to rank generation groups for subsequent swing instability. This is consistent with the conclusions drawn by Edwards et al in reference [41]. Incidentally, the TEM sensitivity method is unable to give useful results in this case because it is a first swing method.

It was then decided to see if a set of composite indices could be selected to perform the generation group ranking for subsequent swing unstable and poorly damped contingencies. The same study described above was used as the base case. The 18 composite indices shown in table 5.6 were selected, giving an average rank error of 4.37. The results achieved with these indices are shown in appendix C.

There are several reasons why this rank error is higher than may be expected:

- The size of the constraints required is often quite large. This means that the small generating groups which are highly stability sensitive will be incorrectly ranked by the time domain data.

- Large constraints will also take the system out of the range for which linear sensitivities will be valid.

- There are four rather than eight contingencies available with which to make the selection of a suitable set of composite indices.

- There are two main causes of subsequent-swing instability, as discussed in section 2.3. Because it is difficult to classify cases separately according to the cause, the set of composite indices selected here has to perform the ranking task for both. This is far more demanding than ranking generation groups in first-swing unstable cases.

Having made all these remarks, the composite index method is still able to rank generation groups acceptably, which would not be possible using a first swing method, such as transient energy function.

Study name	(test 1)	(test 2)	(base case)
Demand level	66% ACS	73% ACS	80% ACS
No. of groups	59 gen.	65 gen.	72 gen.
Keadby	s.s. unstable	stable	s.s. unstable
Deeside	badly damped	badly damped	s.s. unstable
Cellerhead	stable	stable	s.s. unstable
Hinkley P.	s.s. unstable	s.s. unstable	s.s. unstable
Average rank error	3.59	4.32	4.37

Table 5.7: Average generation group rank errors for the two test cases and the base case. Stability of subsequent swing unstable and badly damped contingencies indicated.

5.3.2.1 Different operating conditions

Subsequent swing instability and bad system damping are rarer than first swing instability. Additionally, examples cannot be contrived by simply adjusting fault clearing time. For this reason, the test studies used in this section do not represent such diversity in system demand as the test cases used above for first swing instability. The studies were selected from the output of a CAMEL run and are summarised in table 5.7. The results for these studies show that the indices chosen are sufficiently generic to produce acceptable results at different system operating points. The indices will also work well for badly damped cases. The error for study 'test 1' is significantly lower than the error for the base case because the size of the generation constraints required are less than the base case. Thus the small generation groups are correctly ranked by the time domain constraint analysis.

5.3.3 Computational requirements of composite indices verses hybrid TEF

The main computational overhead associated with the use of composite indices is the selection process. For optimal performance, this process should be performed for each new power system which is to be analysed using a representative set of contingencies. For the 90% ACS base case system used for the selection of the indices for first swing instability, the fully automated selection task takes about one hour per contingency on a modern work station or Pentium PC. Almost all this time is taken calculating the generation constraints using full time domain analysis. Clearly, this time will depend on several factors including:-

- size of the power network
- number of generating groups in the network

- number and complexity of control systems in the network, including AVRs, PSSs, speed governors and facts devices.
- number of generating groups able to restore system stability, because if a group is able to restore stability, a time consuming binary search will be necessary.
- convergence tolerance used for the binary search. 1 MW was used for the studies described above.

Once selected, the set of composite indices is able to make the stability analysis and rank the generation groups very quickly. Again, for the 90% ACS base case study, all generation groups can be ranked for eight contingencies in about 30 minutes. Such rapid analysis is possible because the power system time domain simulation is only required up until the contingency termination point. The values of the composite indices can then be calculated simply and quickly using the set of statistical functions described in section 5.2.5.

In contrast, the hybrid transient energy function method requires the time domain simulation of the system until instability is detected. In situations where the system is stable beyond the first potential energy maxima, a 'second kick' must be applied. The amount of time domain simulation required therefore varies depending on the system's degree of stability. However, typically 0.5 to 5 seconds of time domain simulation will be needed to calculate the system energy margin. Thus, depending on the fault clearing time of the contingency to be studied, and the system's closeness to instability, the composite index method will be 2 to 20 times faster. This is an important advantage for a CAMEL study where the generation groups in the system may need to be ranked hundreds of times.

5.3.4 Summary of results

The composite index method is able to produce better results for ranking generation groups for first swing unstable contingencies than TEM sensitivities. Furthermore, for subsequent swing instability and poor damping, where first swing methods like the transient energy function are unsuitable, a set of composite indices can be selected to achieve acceptable results. A third advantage of the composite index method is its speed, which is of particular value in this application.

Weighing against these advantages of composite indices is the requirement to perform time consuming off-line selection of indices. No such off-line 'adjustment' is required for the hybrid TEF, which should perform similarly, whichever power system it is applied to. The mathematical formulation of the transient energy function may also tend to give its user confidence.

Chapter Six

Constraint Analysis Algorithm

This chapter describes the method used to analyse constraints. The objective of this analysis is to find the constraint cost associated with a particular planning scenario. Although the scope of the work presented in this thesis is limited to constraints associated with stability problems, for completeness an approach which includes thermal and voltage constraints is also outlined.

6.1 Basis of method

The conventional approach to finding stability constraint limits is described in section 1.4.1. In planning time scales, it involves an exhaustive investigation into the sensitivity of operating point variables to system stability and then correlating these relationships with the likely operation of the system. The new approach described here turns the problem around. The likely operation of the system is modelled using plant availability data and generation pool prices. System stability is then directly measured with a select set of contingencies. The elegance of this approach is the immediate reduction of the problem space to the area of interest. As long as the operation of the system is accurately represented, stability problems should be directly identifiable.

Another benefit of this method is that risk, or cost, can be easily assessed. For example, if a particular contingency causes a stability problem in 5% of cases, system operators would need to constrain generating plant in 5% of cases. A cost can be attributed to this constraint which planning engineers can then weigh against the cost of reinforcing the system to make it secure for a larger proportion of the time.

6.2 Overview

The individual elements of the overall method are described in detail below. For clarity, figure 6.1 shows how each of these elements fits together in the complete system. Note that some techniques and models are described below which are not incorporated into CAMEL. This is because their inclusion is beyond the scope of this work, or they have been deemed inappropriate for this application.

A single CAMEL study run aims to test the stability of a power system over a broad range of operating conditions, thereby yielding a constraint cost which is representative of the uncertainties and diversities existing in the future system. To achieve this, a specified number of individual probabilistic simulations are performed, as shown in figure 6.1. For each of these simulations, a level of network demand is chosen. In addition, outages of generation plant caused by planned and forced outages are modelled using a Monte Carlo technique [104, 105]. The stability of the system is tested for each simulation using a fast dynamic security assessor. When an unstable scenario is encountered, a constraint algorithm is used to select appropriate changes to the generation schedule to restore stability. The corresponding constraint cost is then calculated.

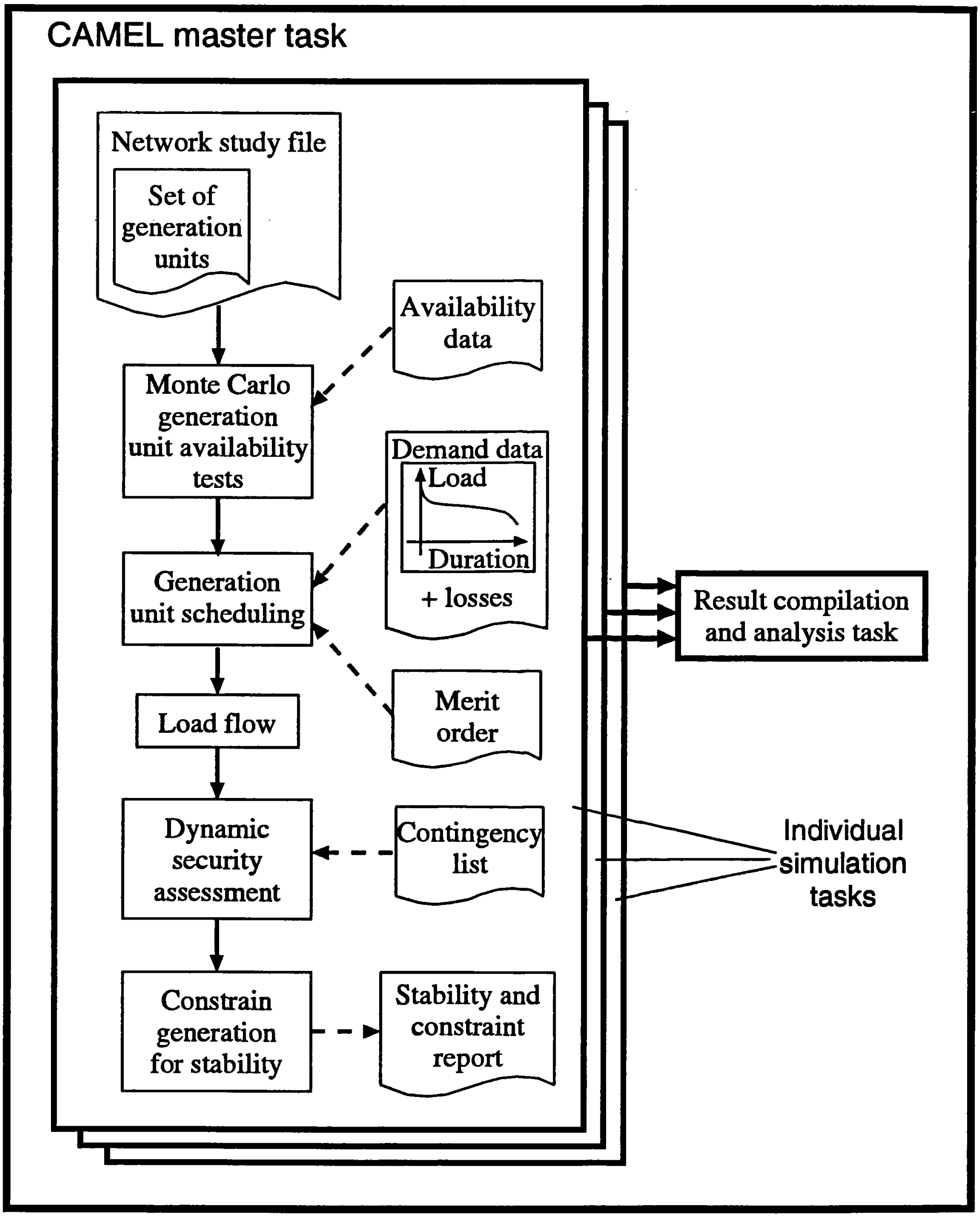


Figure 6.1: An overview of the overall system implemented by CAMEL

The *CAMEL master task* coordinates the individual probabilistic simulations. When complete, the results of all individual simulations are collated and presented to the user in a structured and condensed form.

6.3 Demand modelling

In order to model demand as accurately as possible, a year of operation can be broken down into any number of periods. Typically these are chosen so that each period contains a set of months with similar daily demand curves. For example, the demand in March and November might be similar, so these two months would be grouped to form one period. For each probabilistic simulation, a period is probabilistically chosen according to its duration. So to take the above example, the March and November period will have a 2/12 probability of occurring.

Once the period of a simulation is selected, a level of demand is probabilistically chosen for each probabilistic simulation from a load duration curve. Different load duration curves are used for each period. This is appropriate because demand in March, say, is unlikely to reach very high or very low levels. Table 6.1 is an example of load duration data that might be entered into CAMEL for the March and November period, with the corresponding load duration curve shown in figure 6.2. Note that this table means, for instance, that the system load will be greater than 73.2% of peak ACS demand for 60% of this period.

Active demand at each load point in the system is scaled by a factor SF. This is defined as,

$$SF = \frac{Demand_{NEW}}{Demand_{BASE}} \tag{6.1}$$

Demand as a % of peak	% of time of Mar/Nov period
> 86.0	0
> 81.6	10
> 78.9	20
> 77.1	30
> 75.8	40
> 74.5	50
> 73.2	60
> 71.7	70
> 69.8	80
> 67.7	90
> 65.0	100

Table 6.1: Table of demand data for the March and November operating period.

where $Demand_{NEW}$ is the level of demand chosen from the load duration curve and $Demand_{BASE}$ is the level of demand corresponding to the load flow input file. Hence, the active demand at each load point, $P_{l_{BASE}}$ is scaled by SF, so that the new active demand $P_{l_{NEW}} = P_{l_{BASE}}.SF$.

The demand at grid supply points is composed of many different types of load. For example, if the demand at a grid supply point consists mainly of domestic customers, it will increase because of increased use of heating and lighting. These loads are largely resistive, resulting in only a small relative increase in reactive power consumption [106]. Therefore, to reflect the fact that high demand in this country is to a significant extent due to increased domestic load, reactive demand is scaled by $SF^{0.9}$.

In the load flow input file, the user can specify a number of capacitative shunt network elements. These may be necessary at high demand to compensate for high I^2X losses in transmission lines. The CAMEL algorithm automatically scales these capacitances using the same scaling factor as for the active and reactive demand. The scaling factor is used to find the values of the capacitances, C_{NEW}, according to the following equations:-

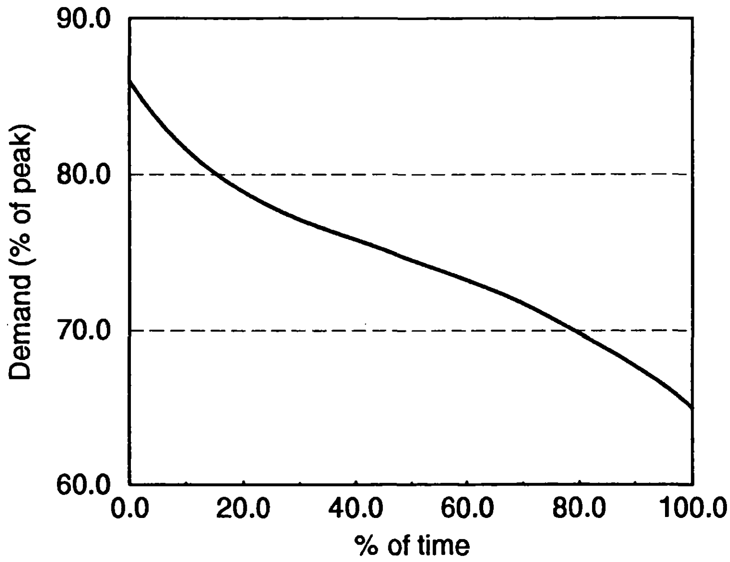


Figure 6.2: Sample load duration curve for the March and November operating period.

$$C_{NEW} = C_{BASE}.(2SF - 1)^2 \quad for\ SF > 0.5 \tag{6.2}$$

$$C_{NEW} = 0.0 \quad for\ SF \leq 0.5 \tag{6.3}$$

Note that this means that the value of capacitances in the network will be zero at half of the base value of demand and below. Care must therefore be taken to specify appropriate values of the base capacitances, C_{BASE}, for the base demand level in the load flow input file. It is recommended that the input load flow file used is for the highest demand level that is to be simulated and that all necessary capacitances are entered such that transmission losses are sufficiently compensated. It has been found that using this model is representative of the way capacitor banks are deployed on the real system.

The program also allows the exclusion of selected busbars or areas from the demand simulation described above. The user may then scale demand at these points by a specific amount. When used in conjunction with excluding generation groups from the Monte Carlo simulation, export or import for various areas of the power system can be loosely defined. These will then be maintained during all simulations. For example, if it is known that a particular demand and generation pattern in North Wales is onerous, the required generation pattern can be set in the input study file and those generation groups are then excluded from the Monte Carlo simulation. In addition, if the demand in this area is excluded from the demand simulation, the export from this area can be kept approximately constant across all simulations.

6.4 Modelling plant outages

6.4.1 Generation plant outages

Generation unit outages fall into two categories; planned outages and forced outages. Planned outages are normally undertaken for maintenance purposes and may be planned months or even years in advance. NGC attempt to coordinate maintenance of connecting transmission plant with generating plant's planned maintenance. Such scheduling of maintenance is beneficial to NGC because constraint costs would normally be paid to a generating company when maintaining the interconnectors of available generation groups. However, due to various practicalities, planned schedules do not always commence as such.

Forced outages are the result of unforeseen plant failures and may therefore occur at any time. They may also upset maintenance plans. Generating companies with plant to be outaged for maintenance may be encouraged to postpone their maintenance plans, while generating companies with plant already out on maintenance may receive sufficient incentive to bring units back on line rapidly.

Given the interaction between planned and forced outages, and uncertainty in future maintenance plans, a simple model has been adopted for this work. Historic forced and planned outage data may be amalgamated into single availability probabilities, examples of which are given in table 6.2. These amalgamated probabilities are entered into the program. Note that because the availability of generating units varies during the year, a different outage rate may be specified for each *demand period.*

	Overall availability including planned and forced outages			
	Dec/Jan/Feb	Mar/Nov	Apr/Sep/Oct	May/Jun/Jul/Aug
CCGTs	91%	90%	86%	89%

Table 6.2: A sample set of availability data for combined cycle gas turbine (CCGT) generating units

Within the simulation, an independent Monte Carlo availability trial is performed on each generating unit within the power network. The trial is performed very simply. A random number, r, is generated according to a rectangular distribution, where $0 \leq r \leq 1$. If the probability of availability of a generating unit is P_A, then the generating unit is only available if $P_A \geq r$.

6.4.2 Transmission plant outages

Whereas generation plant availability is generally in the $80-95\%$ range, transmission plant availability is in the $99-100\%$ range. Forced outages in transmission plant are extremely rare events. Several outages can occur concurrently because of extreme weather conditions. It is therefore very difficult to assign accurate statistical availabilities to specific items of transmission plant because failures occur seldom and sporadically. The accuracy of any simulation which makes use of such figures must therefore be brought into question.

There is also an interaction between generation outages and transmission plant planned outages as discussed in section 6.4.1. Certain concurrent planned transmission outages should not be simulated because they would result in an unacceptable system configuration which system planners would not permit. Computer simulation of these restrictions is generally based on a complex set of maintenance rules, like those forming part of the ongoing work described in reference [107].

These difficulties combined with the lack of reliable data on which to base a realistic model lead to the conclusion that modelling transmission plant outages in the same way as generation plant outages could jeopardise the validity of the model and is not worthwhile. Of course, if the planning engineer is interested in identifying additional investment cost associated with securing the network against maintenance outages, the network database can be altered to remove transmission plant used for the entire CAMEL study.

6.5 Generation scheduling

Available generation units are scheduled on in merit order such that the total generation meets system demand and losses. Losses are estimated from the original load flow file by scaling them in proportion to the demand on the system.

The maximum active electrical power output for each generating unit is calculated from the reactive power limits of the machine given in the load flow data along with the generating unit maximum apparent output power. This procedure is necessary because, prior to the AC load flow required during the stability assessment stage, the unit's reactive output power is not known. Hence, if S is the maximum generating unit apparent output power, and PF_{MIN} is the unit's minimum operating power factor, the maximum electrical output power is given by,

$$P_{e_{MAX}} = S.PF_{MIN} \tag{6.4}$$

PF_{MIN} is found from the unit's maximum reactive power generating capability, $\hat{Q}$, by,

$$PF_{MIN} = \frac{\sqrt{S^2 - \hat{Q}^2}}{S} \tag{6.5}$$

For most generating units, the lagging reactive power capability is greater than the leading one, so this determines the minimum power factor; a value of 0.85 being typical.

All units scheduled on are loaded up to $P_{e_{MAX}}$ with the exception of the *marginal unit*. This is the most expensive of the generation units required and sets the *system marginal price*. A trivial example is shown in figure 6.3. Only 50 MW of the 250 MW capacity of unit $B2$ is required to meet remaining demand, so this unit becomes the marginal unit.

Demand + approx. losses = 900MW

marginal unit

Generating unit	Cost £/MWhr	Capacity MW
C1	0.50	100
A4	0.50	300
F6	1.00	200
A3	2.00	50
B1	2.50	200
B2	3.50	250
•	•	•
•	•	•
•	•	•

Figure 6.3: An example of generation units being scheduled from a merit order, highlighting the *marginal unit*

Generation unit transformers are modelled discretely rather than being included as part of the unit machine model. This allows the machine transformer taps to be evaluated at the load flow stage. The parameters of the equivalent transformer thus depend on the number of generation units scheduled on at each connection point. Hence, once generation scheduling is complete, all transformer parameters are calculated.

Particular generating units or areas of the system can be excluded from generation scheduling. In this case, the generating units retain the MW output levels specified in the load flow input file. This feature is useful when studying particular fixed generation patterns for certain areas. A good example of the requirement for this feature is the Scottish export limit where it may be interesting to study a fixed set of generation patterns as demonstrated in section 7.3.1.

6.6 Static security analysis

After generation scheduling, an AC load flow must be run to find network steady state values of power flow and voltage. All transformer taps and unit reactive power outputs are also evaluated. The load flow program used is OPFL02 [39], a package provided by NGC based on the Newton-Raphson fully coupled solution method [108]. The slack bus is set to the marginal unit so that any error in the estimate of system losses can be balanced by a change in generation there.

It is possible to specify a set of thermal transfer limits which must be observed. These can take the form of power transfer in a single transmission line, or a group of lines. Should any simulation not meet these criteria it will be discarded at this point. It is important to note that enforcing thermal constraints in this way may give an unrealistic and optimistic view of constraint costs because certain problematic demand/generation patterns are not allowed to reach the stability analysis and constraint phase. In the future, this part of the algorithm would be replaced by a full static security analysis, capable of constraining generation to meet thermal and voltage criteria. This should be straightforward development work: ESCORT [38] already provides a means of calculating thermal constraints using linear programming techniques, while work carried out by Bell et al at the University of Bath [36] demonstrates the use of fuzzy expert system optimisation techniques to provide an integrated approach to thermal and voltage constraints. Both methods also yield the advantage that system power flows under contingency conditions may be examined and altered as necessary.

6.7 Transient stability analysis

Transient stability is assessed using a dynamic security assessment (DSA) tool, *PowSim Engine* (PSE) previously developed at the University of Bath and described in [109, 110]. This uses the load flow results and data describing the power system dynamic elements to assess the transient stability of the system for a specified number of contingencies. The results returned by PSE relate to each contingency, and place the time domain simulation results of the system into one of four classes; well damped, badly damped, pole slip and diverging to pole slip but no pole slip detected during the duration of the simulation.

Because stability is dependant on the disturbance applied to the system, it is important that the list of contingencies used at this stage relates to the constraints which are being analysed. Often such contingencies will include faults on 'weak' interconnections in the system. Past experience gained by the planning engineer, or a few preliminary studies using a large list of contingencies may be beneficial in identifying a suitable set of contingencies.

Provided the list of contingencies is well chosen, the results of the DSA should give a good measure of the part of the system's transient performance that is affected by the constraints of interest.

6.8 Generation Constraints

Occasionally a certain generation and demand pattern will be unstable for a contingency or set of contingencies. Under these circumstances, the constraint algorithm within CAMEL will find a new generation schedule while attempting to keep the constraint cost to a minimum. This is achieved in three steps:

① Determine which generation groups are causing the instability.

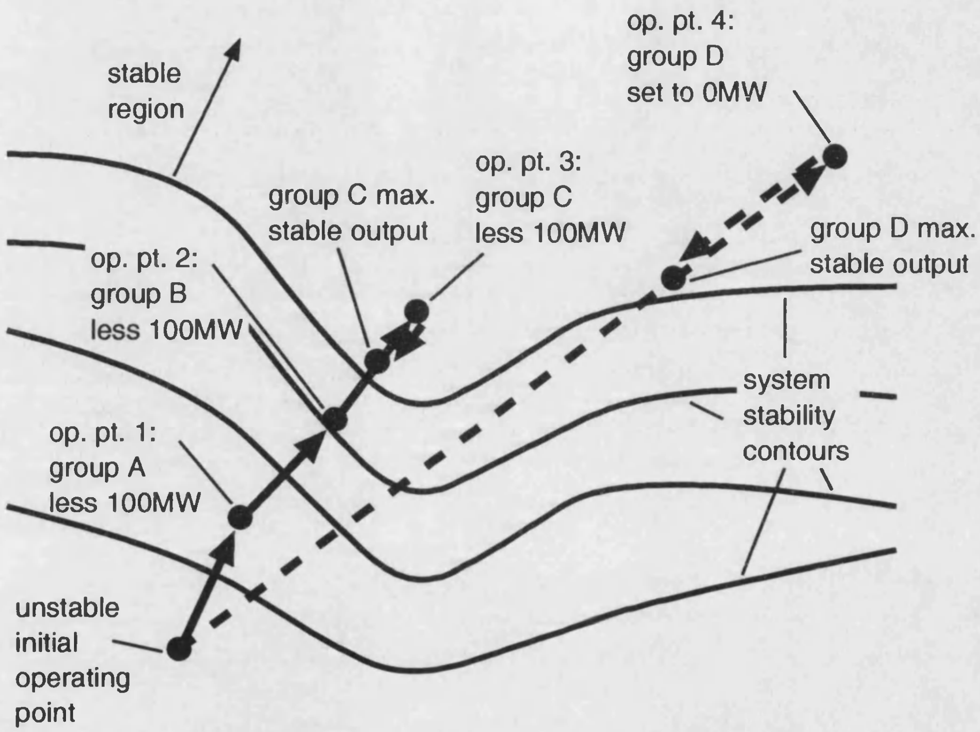
② Try to find a low cost generation schedule to restore stability for each individual contingency.

③ Amalgamate all the generation schedules found at step ② to produce one consistent, stable, low cost schedule.

This algorithm is implemented in the software in two sections. The first section implements steps ①&②, and therefore determines all *single contingency constraints.* The second section amalgamates the results of all single generation constraints. The description of the algorithm below is therefore broken down into these constituent parts.

6.8.1 Single contingency constraints

The algorithm described below is supplemented by the diagram shown in figure 6.4.



Finding a low cost set of constraints:-

1) Take a 100MW step in the direction of the steepest gradient, i.e. select the most stability sensitive generation group to constrain by performing a linearisation at the present unstable operating point. Continue until the system is stable and then use binary search to find the maximum stable output of the last generation group used. Illustrated above with groups A, B and C.

2) Look for low cost constraints using single generation groups and binary search alone. Selection of groups to try is based on pool offer price and stability sensitivity at the initial unstable operating point. Illustrated above with group D.

Figure 6.4: An overview of the technique used by CAMEL to find low cost single contingency constraints.

For an unstable contingency, find the minimum amount of generation that must be constrained as follows:-

① Divide the available generating groups into two categories, A and B. Category A contains all the generating groups which improve system stability when constrained off. Category B contains the remaining generating groups in the system together with any available out of merit generation.

② Rank generating groups in category A by their ability to provide the largest improvement in system stability for the smallest change in active power output. Rank the generating groups in category B by pool offer price.

③ Reduce the output from the most effective groups from category A and balance the generation change by constraining on the least expensive generation from category B.

④ Test system stability using the DSA. If the system is still unstable, return to step ①.

Steps ①&② are achieved using the stability analysis tool described in chapter 5.

After each constraint action, the stability of the system is tested using the DSA. This ensures that any solution arrived at meets stability requirements.

The value of the generation constraint implemented in step ③ is set small enough to keep stability effects approximately linear. From experience, a maximum value of about 100 MW was found to be practical for large systems with 50-100 generating groups. This is consistent with the findings of Fouad et al in reference [73]. If additional accuracy is required, the step size can either be reduced, or a binary search technique can be used with the 100 MW range as a starting point. However, both these solutions obviously have run time implications. At present, the use of a binary search is preferred because it is not necessary to re-linearise the system at each search iteration. The number of iterations, *iter*, required to reach an accuracy of *tol* MW with an initial range of *range* MW can also be strictly determined using equation 6.6.

$$iter = \frac{log(range) - log(tol)}{log(2)}. \tag{6.6}$$

This means, for example, that an accuracy of 1% can be achieved in 7 iterations.

It is possible to specify sets of generation that the above algorithm will use when making constraint-off actions. Each set is specific to a single contingency. The aim of this is to allow the user to reduce the search space of the algorithm through expert knowledge of the problem, thereby reducing program run time. If a set of generation is not specified, any generation group in the system may be considered for constraint-off actions.

6.8.1.1 Cost

The algorithm described above should allow the calculation of the minimum amount of generation that must be constrained to restore stability. However, prior to these constraints, the system may be close to a stability limit, such that the selection of a single generation group with a suitable pool offer price could result in a lower cost set of constraint actions. For example, it is necessary to constrain off a generation group, say GEN-X, by 50 MW to restore stability to a given system. Say the cost of this action is £5000/hr. However, a less 'stability sensitive' generation group, say GEN-Y, would need to be constrained off by 70 MW. The cost of constraining off GEN-Y is only £3000/hr. Thus, GEN-Y should be chosen. CAMEL explores such possibilities in an efficient manner by descending the stability ranked list and only attempting to make generation changes at groups which meet two criteria:-

① The generation group should be large enough to sustain a reduction in output at *least* as large as the maximum constraint-off action found so far.

② The pool offer price of the generation group should be greater than the pool offer price of the group used for the lowest cost set of constraints found so far.

Notes:-

- Single generation group constraints are tested using only a binary search. Initially, the stability of the system is tested with the output of the group set to zero. If the system is stable, a binary search will be employed to find the maximum stable output of the group.

- The generation group must have a greater pool offer price if there is to be a possibility of its constraint resulting in a lower overall constraint cost. This is because the constraint-off cost is given by $(SMP - offer\ price).g$ where g is the size of the generation change.

- Criterion ① requires that the groups are ranked in order of 'stability sensitivity', and therefore it is known that the constraint required with group Y, say, will be greater than that for group X if group Y is ranked above group X.

- If the lowest cost set of constraint-off actions was found with more than one generation group, i.e. it was found as described in section 6.8.1, a *composite pool offer price*, $CPOP$, must be found using

$$CPOP = \frac{1}{\sum^{i} g_i} \sum^{i} POP_i.g_i \tag{6.7}$$

where g_i is the constraint required for group i and POP_i is the pool offer price for group i.

This search technique is illustrated in the following example.

A large system is known to be unstable for a particular contingency. The generation groups in the system which may be constrained off in order to make the system more stable are placed in category A and ranked accordingly. The remaining groups are placed in category B and ranked by pool offer price, in the manner of table 6.3. The group which will restore system stability for the smallest change in MW output is therefore GEN-71. It is found that by constraining off this group by 665MW, system stability is restored. The generation shortfall is made up by constraining on the cheapest groups from category B, i.e. GEN-60 and GEN-61. System marginal price is £12.90/MWhr, and the cost of constraint actions is calculated using the equations given in section 1.4.3.

Rank	Generation group	Constrained On (MW)	Constrained Off (MW)	Pool offer price £/MWhr	Cost £/hr
A	GEN-71	-	665	10.3	1729
	GEN-67	-	-	11.5	-
	GEN-69	-	-	1.5	-
	⋮	⋮	⋮	⋮	⋮
B	⋮	⋮	⋮	⋮	⋮
	GEN-60	571	-	13.2	7537
	GEN-61	94	-	12.9	1213
				Total	10479

Table 6.3: Single generation constraints and cost found using GEN-71

Now, because the offer price of GEN-67 is higher than that of GEN-71, it is possible that constraining GEN-71 off instead may be less expensive. The constraint algorithm must therefore test this alternative. The results are shown in table 6.4. The total cost of these constraint actions is greater than those previously found with GEN-71. All other groups below GEN-67 in category A have lower offer prices and, since they are also less stability sensitive, will be more expensive to constrain.

The constraint algorithm saves considerable computational effort by stopping at this point as the lowest cost set of constraint actions has been found for this contingency.

Rank	Generation group	Constrained On (MW)	Constrained Off (MW)	Pool offer price £/MWhr	Cost £/hr
A	GEN-71	-	-	10.3	-
	GEN-67	-	771	11.5	1079
	GEN-69	-	-	1.5	-
	⋮	⋮	⋮	⋮	⋮
B	⋮	⋮	⋮	⋮	⋮
	GEN-60	677	-	13.2	8936
	GEN-61	94	-	12.9	1213
				Total	11228

Table 6.4: Single generation constraints and cost found using GEN-67

Note that if two or more generation groups must be constrained to restore stability, it is no longer practicable to find low cost constraints. Even if only two generation groups are needed, all possible combinations would need to be tested. If category A consists of only ten groups, then there are 100 combinations that must be tested. The problem is further complicated by the non-linear nature of the stability domain, described in chapter 3, which makes the use of linear programming techniques unsuitable.

An engineering solution is chosen to the problem of finding a *low* cost solution. As described in section 1.4.3, the cost of constraining generation can be broken down into

$$Constrain-off\ cost = (SMP - offer\ price).g \tag{6.8}$$

$$Constrain-on\ cost = offer\ price.g \tag{6.9}$$

However, the *offer price* in equation 6.8 will be less than the *SMP* because generation to be constrained off is in merit. Also, the *offer price* in equation 6.9 will be greater than the *SMP* because the generation is out of merit. Now, the total value of generation in the system must remain constant, so the value of g in both equations is the same. This means that the constrain-on cost will always form the larger proportion of the total constraint cost. Hence, if the algorithm used simply minimises g, then the constrain-on cost will automatically be minimised. Because this forms the larger proportion of the total constraint cost, a low cost solution will be found. This is the approach adopted for this work.

It is expected that a planning study will rarely result in scenarios that are a long way beyond stability limits and therefore, single generation constraints will normally be adequate to deal with any instability. For these cases, constraint costs calculated should be close to optimal. In the event that a multi-generation-group constraint is necessary, a low constraint cost will be found by minimising generation changes.

A typical set of constraint actions for a single contingency is shown in figure 6.5, while some examples of this constraint algorithm in use are given in section 7.2.3.

```
Constraints for study 14

Group GEN-19 constrained on  by  130.0MW at a cost of £1417
Group GEN-66 constrained off by   20.0MW at a cost of £ 188
Group GEN-67 constrained off by  110.0MW at a cost of £1034

Total cost of constrained on  gen = £   1417 /Hr
Total cost of constrained off gen = £   1222 /Hr

Total constraint cost             = £   2639 /Hr
```

Figure 6.5: An example of a set of constraint actions taken from a CAMEL output file.

6.8.2 Amalgamation of single contingency constraints

When the previous stage is complete, a set of low cost constraint actions will exist for each unstable contingency. These sets of constraint actions must now be amalgamated to find a single low cost generation schedule which meets the stability requirements of every contingency. In the final generation schedule, the largest constrain-off action for each generation group will be selected. The resulting shortfall in generation is made up by constraining on the least expensive groups from the available out-of-merit generation.

6.8.3 A note about transmission losses

It is appropriate at this point to mention transmission losses, since changes in the generation profile will have an effect on them. This, in turn, will change the system demand and operating cost.

For the purposes of the work described in this thesis, transmission losses have been neglected. This has been done for two reasons:-

① Transmission losses on the UK NGC system, with which the CAMEL software has been developed and tested, are of the order of 1-2%. This is very low and therefore changes in generation will only change the total demand on the system by a very small amount.

② The constraint costing model used by NGC does not take the contribution to system losses made by individual generation groups into account.

The methods described here could, however, be extended to other more radial power systems, with higher losses. This is achieved by using a marginal bid price for each generation group which takes the cost of losses related to the generation group into account. On highly-meshed power systems, such as the UK National Grid, this is not practical.

6.9 Multiple simulations and collation of results

The above process, from selection of demand, through generation outages, security assessment and constraint cost calculation is called an individual probabilistic simulation. The results for all of these simulation are collated by the CAMEL master task. An empirical performance index, called the *badness index* is used to monitor the overall results of a CAMEL study while it is still in progress. This is useful as it allows for early termination of the study if the number of stability problems is either unacceptably high, or low enough not to be of concern. Confidence limits of 95% are calculated for the badness index, so that a maximum and minimum value may be assigned. Should these values fall outside user defined tolerances, the CAMEL study will be halted.

The badness index is defined as the arithmetic mean across all contingencies of,

$$Badness = \frac{(\frac{(100-a)}{2} + d)PS + (\frac{(100-a)}{2} - d)DI + aBD}{(\frac{(100-a)}{2} + d)} \tag{6.10}$$

where d is the duration of the time simulation and PS, DI and BD are the percentage probabilities of a pole slip, divergence and bad damping respectively. a is the maximum percentage of the badness index which may be attributed to bad damping. The value of a is empirically set to 10% at present. The duration of the simulation is included in this formula to reflect the fact that diverging cases would tend to diverge to a pole slip for a longer simulation duration. Note that a 100% probability of a pole slip gives a badness index of 100%.

The data and results for each individual simulation are stored for subsequent analysis if necessary.

6.10 Program output

```
(C)onstraint (A)nalysis using (M)onte Carlo (E)valuation of (L)oading


temp directory '.cmtmp' does not exist ... creating ... done.
Input file is '../../oasis/2200-study/m87b906.pse'
Transfers file is 'm87b906.tx'
Output file base name is 'sa/m87.sa'
PSE results file is 'sa/PSEresults87.sa'
Parameter file is 'm87b906.par.sa'
Contingency file is '../../oasis/2200-study/m87b906.scot.ct'
PSE time step is 5ms and simulation duration is 12s

Demand variation in specified areas is    0MW
Calculating constraint costs

CAMEL running ...

Finished running simu. 0100 : time to completion 00:00:00 : badness 21.6

1 Monte Carlo re-runs because of failed load flows

Total run time  :       032:00:22
Assessment time :       004:03:40
Constraint time :       027:54:03

Results obtained from 100 simulations of 4 contingencies

Ct.   Name                              %PS    %DI    %BD    %BN +/- L      Cost/yr

   1 Strathaven                        33.0    0.0    0.0   33.0 +/-  9.3  £   146k
   2 Eccles                            30.0    0.0    0.0   30.0 +/-  9.1  £   144k
   3 Harker-Hutton                      2.0    0.0    0.0    2.0 +/-  2.0  £     3k
   4 Penwortham-Padiham/Kearsley        0.0    0.0    0.0    0.0 +/-  0.0  £     0k

Key:    PS = Pole slip
        DI = Diverging, but no pole slip detected in 12s
        BD = Badly damped
        BN = Badness index for contingency
        L  = 95% Confidence limits of badness index

                     Summary
                     -------

Average badness of study is                    16.3+/-5.3 %
Probability of a stability problem is               33.0%
Average constraint cost over study is      £28976.404k/yr
```

Figure 6.6: Results of a study where 100 probabilistic simulations were run using a list of 4 critical contingencies.

A typical set of results are shown in figure 6.6. The results of each study are broken down by contingency, making it easy to identify areas where problems are most prevalent. For example, the 'Strathaven' contingency caused a pole slip in 33.0% of cases, while the 'Eccles' contingency caused a pole slip in 30% of cases and the 'Harker-Hutton' contingency caused a pole slip in 2% of cases.

The cost of securing each contingency in unstable cases is also given. This can be useful as a contingency may frequently cause stability problems while the associated constraint cost may in fact be low, and vice versa. The total constraint cost for the whole study is given at the bottom of the results. It is important to realise that the constrained generation schedule calculated for each probabilistic simulation should satisfy *all* contingencies. Hence, it is not possible to assign proportions of the total constraint cost to each contingency. Also, it will usually be the case that the sum of the constraint costs for single contingencies will be greater than the total constraint cost.

The results summary also gives the probability of a stability problem in one study. This is useful when determining the diversity of stability problems. In the 100 simulation CAMEL study shown above, the probability of a stability problem is 33% and all contingencies are unstable in up to 33% of cases. This means that certain generation patterns are onerous for all contingencies simultaneously. This information can be beneficial in deciding if the selected set of contingencies characterise the same stability problem.

6.11 Implementation

CAMEL's algorithms and methods, described in this chapter, have been implemented in their entirety by the author using ANSI standard 'C' code. The software is split into several modules to allow for ease of maintenance and future modification.

The PSE program had to be substantially modified for this application to allow for the calculation and extraction of the composite indices described in chapter 5. OPFL02 was used without modification, although data file converters had to be written to make the program's input and output compatible with CAMEL and PSE.

Chapter Seven

Results and Analysis

This chapter presents results obtained using the CAMEL software. There is currently no other program available which is capable of explicitly calculating stability constraint costs by any method. For this reason, this chapter focusses on typical set-up and use of CAMEL, rather than comparisons with other tools.

The generic algorithms which are implemented in the CAMEL software are the key outcome of the work described in this thesis. Therefore, the results presented in this chapter are not an exhaustive display of all the features of the CAMEL software. This would be impractical in the space afforded here. Instead, the results are intended to supplement the methods described in chapter 6 and show how CAMEL might be exploited to analyse a typical large planning problem. However, the CAMEL software is in no way specific to a particular power network or stability constraint. Indeed, on-going field trials of the software at the UK National Grid company, where CAMEL has been used to analyse other power systems, demonstrate this.

The studies presented in this chapter relate to the power transfer limitations of the interconnections between the SP and SHE systems in Scotland, and the NGC system. This particular constraint has been chosen for three reasons:-

① Historically, large exports from the Scottish network have proved problematic [6, 43, 49]. Power oscillations have occurred in the past, such that long term measures have been necessary including the installation of power system stabilisers and an SVC at Harker with power oscillation damping (POD) capability [69].

② Because both the SP/SHE and NGC systems are relatively well meshed systems interconnected by only a few long transmission lines, loss of synchronism between the two systems can occur if the stable export limit is exceeded. Inter-area oscillations and system splits are notoriously difficult problems to analyse and counter, making this part of the network a challenging test for CAMEL.

③ The export limit between the systems is complex because it varies depending on network demand and generation patterns. This is exactly the sort of problem which CAMEL is intended to handle efficiently.

The first section of this chapter describes the data used for the studies investigated in this chapter. The second section looks at some of the features of CAMEL with a view to selecting the correct set up for a study. The constraint algorithm is also demonstrated in this section. The final section of the chapter examines some particular case studies involving the SP/SHE export discussed above.

7.1 Study data

The power network used for the studies presented in this chapter is based on NGC's existing and authorised system for the 1997/98 year of operation. The system consists of around 900 busbars and 1800 transmission links. The supergrid part of the system is shown in figure A 4.3 of reference [4] which has been directly copied as figure 7.1 of this thesis. Data for the transmission network is listed in table B 2 of reference [4].

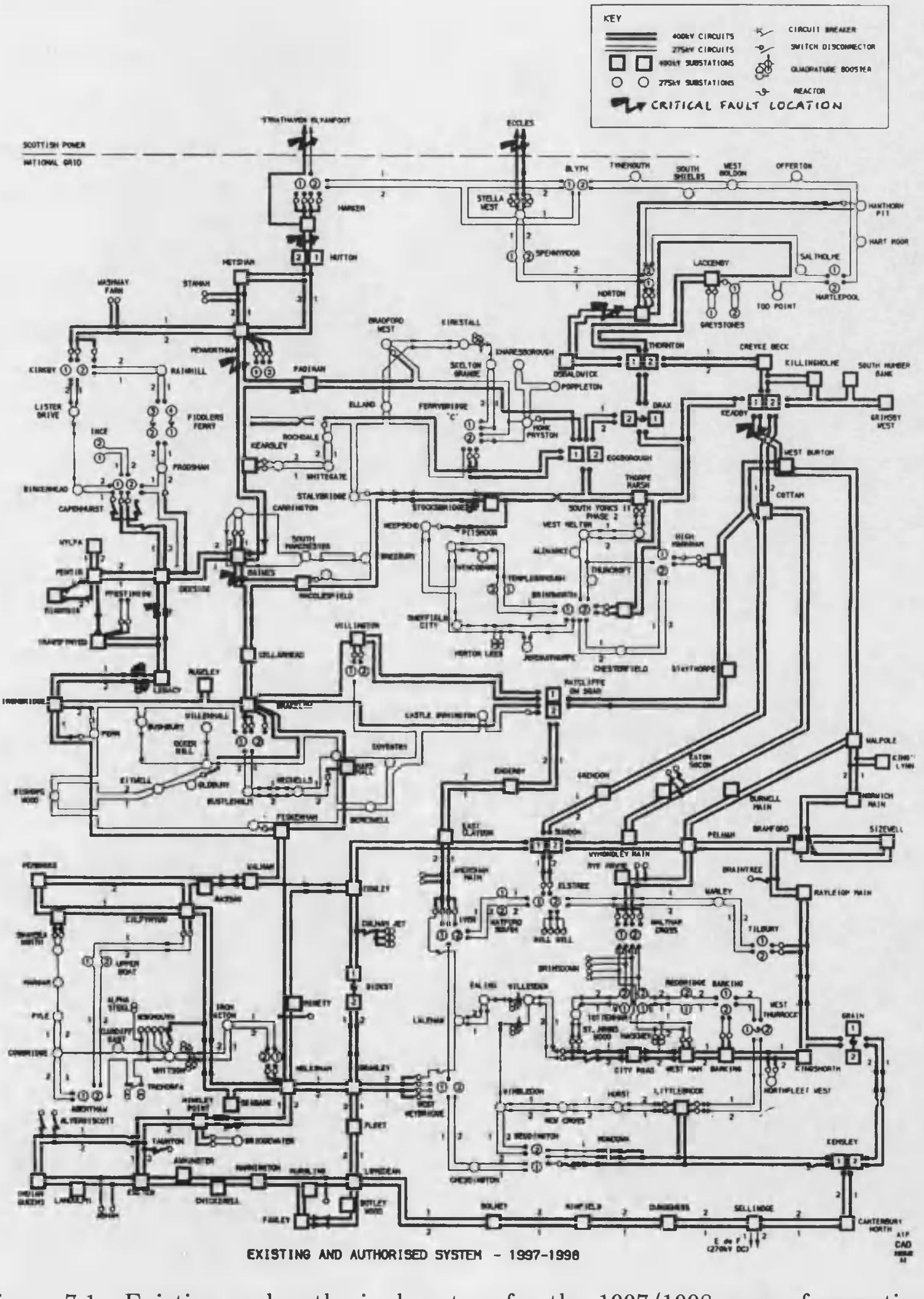


Figure 7.1: Existing and authorised system for the 1997/1998 year of operation reproduced from the 1996 Seven Year Statement with the permission of the National Grid Company. The positions of critical faults are also shown.

Base case demand on the system is 48 GW which equates to about 90% ACS. A total of around 49.5 GW of installed generation is specified in 87 generating groups. Once possible generation outages are taken into account, the maximum demand level that may be modelled by CAMEL with this generation is approximately 85% ACS. The system also contains 12 SVCs which are dynamically modelled.

The main differences between the study network and the current NGC system include reinforcements to the interconnections with SP/SHE and an extra circuit between Lackenby and Thornton in the North East.

7.1.1 Contingency list

Eight critical contingencies have been used to test the stability of the system for the majority of the case studies presented in this chapter. The locations of these eight contingencies are shown in figure 7.1, while the faults and their clearing sequences are illustrated in detail in appendix A. The stability of these eight contingencies is known to be associated with the power export limit from the SP/SHE system.

All the contingencies model solid three phase to ground faults. Although these faults occur on transmission circuits, the distance from the fault to the nearest busbar is set to zero. Hence, provided the fault locations are chosen correctly, these contingencies represent worst case conditions.

7.1.2 Outage data and merit order

The generation outage, or availability data used is classed by plant type and is given in appendix table D.2. This may be cross referenced with appendix table D.3 to obtain the probability of availability of each generation group in the system. Note that the values for generation availabilities include both planned and forced outages.

Annual generation availability data is subdivided into four periods of the year. Each period is made up of two, three or four months, during which time the probability of availability of a particular plant type is assumed constant. Each period has its own load duration curve, as described in section 7.1.3.

Note that appendix table D.3 also contains the offer price, owning generation company, and maximum number of available generating units for each generation group.

7.1.3 Network demand

Different load duration curves are used for each of four outage periods. There are, therefore, four load duration curves which have been derived from the single load duration curve given in reference [4]. The data for this yearly curve and the four derived period curves is given in table D.1, while the load duration curves themselves are shown in figure D.1.

7.1.4 Thermal transfer limits

To monitor and, at times, restrict the value of the Scottish export, the lines connecting the SP/SHE and NGC systems were entered into CAMEL as a thermal transfer limit.

7.2 Performance of CAMEL

7.2.1 Number of simulations

Within one study, CAMEL performs a user-specified number of individual probabilistic simulations. The badness index output by CAMEL is intended to help the user specify a number of simulations, such that the results can be considered sufficiently accurate while using the minimum of computing time. As an example, a CAMEL study was run with the study data described above. The number of individual probabilistic simulations was set to 800 and the badness and badness confidence limit were output at the end of each simulation. The results of the first 200 simulations are shown in the graph in figure 7.2.

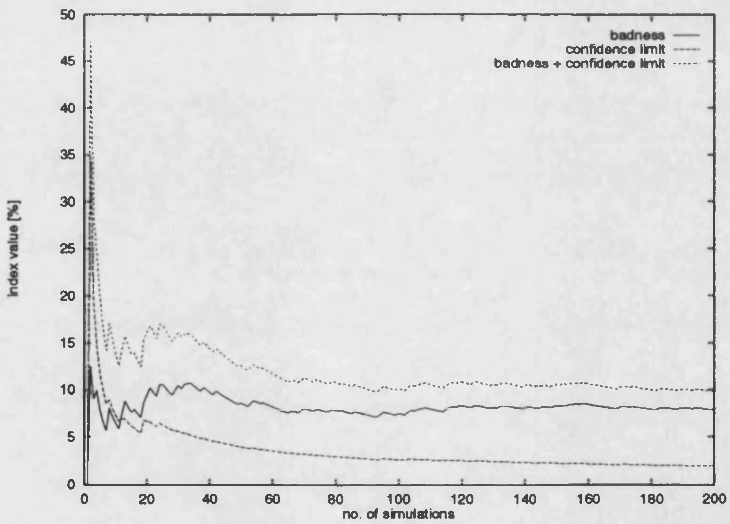


Figure 7.2: Plot of study badness and badness confidence interval against the number of simulations for a typical CAMEL study.

From the graph, it can be seen that the value of the badness index settles to a reasonably constant value after 80-100 simulations. In fact, after 80 simulations, the value of the badness index is 7.9 ± 3.0. After 800 simulations, the badness index is 8.0 ± 1.0. Two observation can be made here. Firstly, the value of the badness after 80 simulations is very close to the value after 800 simulations. Secondly, for a ten-fold increase in the number of simulations, the confidence limit has only decreased by a factor of three.

For these reasons, the CAMEL studies presented in this chapter have been performed with 100 individual simulations. Of course, CAMEL can be set to terminate before the specified number of simulations if the sum of the badness index and its confidence limit fall below a user-defined value. However, to allow easy comparison between the results of different studies, this feature has not been taken advantage of here.

It should also be clear from figure 7.2 that there is a minimum number of simulations which should be carried out. The badness index varies a great deal initially and is occasionally lower during this initial period than the value to which it finally converges. In fact, the value of the badness index is zero until the second simulation when an unstable contingency is first encountered. The use of the confidence limit here as part of the stopping criteria helps to ensure that the CAMEL study is not stopped before a representative sample has been made. However, CAMEL allows the specification of a minimum number of simulations. 20 would be a suitable number for this size of study.

7.2.2 Program run time

The run time of the CAMEL program can be expressed as:-

$$t_{CAMEL} = n_s(t_{lf} + t_{DSA} + t_{constraint}) \tag{7.1}$$

where n_s is the number of individual probabilistic simulations, t_{lf} is the time taken for the load flow task, t_{DSA} is the time taken for the dynamic security assessment task and $t_{constraint}$ is the time taken to make any necessary constraint actions.

t_{lf} is mainly dependant on the size of the power system (number of nodes). The number of generation groups in the system also affects the run time of the load flow because group transformer taps and reactive limits must be evaluated at each iteration.

t_{DSA} is best expressed as:-

$$t_{DSA} = t_{timesim}.n_c \tag{7.2}$$

where n_c is the number of contingencies to be simulated and $t_{timesim}$ is the time taken to perform the time domain evaluation of one contingency. $t_{timesim}$ is primarily dependant on the following factors:-

- the size of the system
- the number of generation groups in the system
- the number of dynamically modelled loads in the system
- the size and complexity of the control systems modelled, such as AVRs, governors and PSSs.
- the integration time step which must be used to model these control systems to the desired level of accuracy.
- the duration of the time domain simulation. Note that a particular simulation will be terminated early if a pole slip is detected.

$t_{constraint}$ is dependant on the following:-

- all the factors which affect t_{lf} and $t_{timesim}$
- the number of individual probabilistic simulations which are unstable in each CAMEL study.
- the number of contingencies which are unstable in each unstable probabilistic simulation.

- the total size of the constraint actions which are required to restore the stability of each unstable contingency. This affects the number of re-linearisations which are required.
- the required accuracy of the binary search used.
- the number of alternative single generation group constraints the CAMEL algorithm must test. This depends on the size of the constraints required, the number and size of the generation groups in the system and their pool offer prices.

Thus, the run time of the CAMEL program for a given study is difficult to predict in advance. As well as all the factors stated above, the run time will also depend on the computer hardware used for a study. The best performance achieved with CAMEL was when using an Intel 200 MHz Pentium Pro processor-based machine. The run time for a 100 simulation CAMEL study with eight contingencies, excluding constraints, was about 1 hr 30 mins for the power system described above. The security assessment was made with up to 12 s of simulation for each contingency and an integration time step of 10 ms.

The time taken to evaluate constraint actions for the most severe study described in section 7.3.1 below, where 75% of the probabilistic simulations were unstable for at least one contingency, was 7 hrs 45 mins. For the least severe study, when only 4% of studies were unstable, the time taken to evaluate constraints was 15 mins.

7.2.3 Demonstration of Constraint Algorithm

The following sections are a 'walk through' of some constraints evaluated during a real CAMEL study. One probabilistic simulation has been chosen which requires reasonably simple constraint actions for two contingencies. However, the example is

Generation group	Stability rank	Pool offer price (£/MWhr)
PEHE81	1	1.50
CRUA82	2	4.99
CRUA81	3	4.99
HUER81	4	4.99
CHAP81	5	0.00
LOAN81	6	4.99
LOAN82	7	4.99
COCK81	8	4.99
TORN81	9	4.99

Table 7.1: Generation stability ranking for a subsequent-swing-unstable contingency at Eccles.

sufficiently involved to supplement the explanation of the constraint algorithm given in chapter 6.

7.2.3.1 Low cost constraints

This example shows how CAMEL reaches a least cost set of constraint actions for a subsequent swing unstable contingency at Eccles.

11 generation groups have been specified in the parameter file for use when stabilising the Eccles contingency. Of these 11 groups, 9 are in the unstable system and are ranked for improving the stability of the Eccles contingency as shown in table 7.1. The rest of the available generation in the system is ranked by pool offer price.

PEHE81 is the most stability sensitive group and will be used for constrain-off actions first. The constraint algorithm makes the largest change in the output of group PEHE81 for which the linear sensitivities are assumed to be valid, i.e. 100 MW. The marginal group, DRAX82, is constrained on by 100 MW to compensate for the resulting generation shortfall. Contingency Eccles is re-tested and found to be stable. Binary search is used to find the minimum constraint of group PEHE81 consistent with system stability, which is 31 MW. The cost of both the constrain-on and constrain-off actions is found to be £476/hr.

Because the most stability sensitive generation was used for these constraint-off actions, CAMEL has now found the minimum value of the constraints required, i.e. 31 MW. CAMEL now performs a search, testing the remaining stability-ranked generation in the system to see if *single generation group* constraint-off actions will result in a lower constraint cost. CAMEL will only attempt to find constraints with groups which:-

① have an output greater than the minimum constraint required so far and

② have a pool offer price greater than more stability sensitive generation groups tested so far.

Point ① prevents testing constraints at generation groups when they are impractical because of the group's limited output capacity. Point ② prevents testing groups which will not yield a lower overall constraint cost. (The lower the pool price, the greater the constrain-off cost because constrained-off generation is paid the difference between system marginal price and the pool offer price.) CAMEL is therefore looking for a generation group with an output greater than 31 MW and a pool offer price greater than £1.50.

CAMEL moves down the stability ranked list obtained at the original unstable operating point. Group CRUA82 is the first to be tested (a single group constraint has already been found using PEHE81). CRUA82 is removed from the system and the Eccles contingency tested and found to be stable. A binary search then determines the minimum constrain-off action using CRUA82 to be 37 MW. The cost of this action and the corresponding constrain-on action at DRAX82 is £435/hr. This constraint cost is thus lower than that found with group PEHE81. Further single generation group constraints are not tested because, as can be seen from table 7.1, the other groups have a pool offer price less than, or equal to, group CRUA82. Provided the stability ranking is correct, the lowest cost constraint set has been found.

7.2.3.2 Amalgamation of constraints

The Strathaven contingency is first-swing unstable for the same probabilistic simulation as the example given above. The constraint algorithm finds that the smallest set of constraint actions required to restore stability involve constraining group CRUA81 by its entire output (99 MW) and group CRUA82 by 62 MW. Group DRAX82 is used to compensate for the generation shortfall which these actions imply.

No single generation group constraints are tested in this instance because the composite pool offer price for groups CRUA81 and CRUA82 is £4.99. All the other generation groups which may be used for constrain-off actions have pool offer prices less than, or equal to, this value.

The constraint actions for both the Strathaven and Eccles contingencies are shown in table 7.2. The bottom of the table shows the amalgamated set of constraint actions which are found by taking the largest constrain-off actions at each generation group and constraining on sufficient generation to compensate for these.

Note that this is a slightly unusual case because the constraints required for the Strathaven contingency completely encompass the constraints for the Eccles contingency. In other words, provided the Strathaven contingency is to be secured, the Eccles contingency will also be secured at no additional cost.

Contingency (or amalgamation)	Generation group	Constrained On (MW)	Constrained Off (MW)	Cost £/hr
Eccles	CRUA82	-	37	125
	DRAX82	37	-	310
			Total	435
Strathaven	CRUA81	-	99	334
	CRUA82	-	62	209
	DRAX82	162	-	1358
			Total	1901
Amalgamated schedule	CRUA81	-	99	334
	CRUA82	-	62	209
	DRAX82	162	-	1358
			Total	1901

Table 7.2: Amalgamated generation constraints for the Eccles and Strathaven contingencies.

7.3 Case studies

7.3.1 Case 1: Set Scottish generation pattern

For the first case study, the generation in the Scottish system was excluded from the Monte Carlo availability trials and merit order scheduling. The generation pattern in this part of the network was thereby kept constant. In fact, the set generation pattern used for this study was a 'worst case' supplied by NGC.

The demand on the Scottish system was also excluded from the demand simulation. A series of nine 100 simulation CAMEL studies were run during which the value of the Scottish export was varied by scaling the demand level in Scotland. The generation and demand on the NGC system were free to vary in accordance with the individual probabilistic simulations.

The studies were conducted in order to answer three main questions:-

Export (MW)	Probability of a stability problem (%)	Average demand of bad simulations (% ACS)	Study badness ± conf. int.(%)	Constraint costs £k/yr
1900	0.0	-	0.0±0.0	0
2000	4.0	76.3	0.3±0.3	24.8
2100	10.0	78.4	0.6±0.4	189
2200	16.0	79.5	1.1±0.5	403
2300	31.0	77.9	1.8±0.6	2,420
2400	28.0	74.2	0.9±0.3	3,380
2500	28.0	65.5	0.8±0.3	1,610
2600	69.0	70.4	3.7±0.8	6,310
2700	75.0	72.3	9.2±1.5	11,900

Table 7.3: Table of badness index and constraint cost for a set of CAMEL studies performed at different values of Scottish export. Set 'worst cast' Scottish generation pattern.

① What is the maximum export from the Scottish system consistent with absolute stability of all contingencies?

② How does the stability of the system change above the stable export limit?

③ What constraint costs are incurred above the stable export limit?

The results of the CAMEL studies are shown in table 7.3. By performing studies with the export set at values between 1900 and 2000 MW it was possible to establish that the maximum value of the export consistent with complete stability of all contingencies in all simulations is 1910 MW.

Figure 7.3 is a graph of the badness index for the studies tabulated above. From this it can be seen that the study badness rapidly increases above an export of around 2500 MW. This is because a large number of individual probabilistic simulations are unstable for the Strathaven fault, particularly at an export of 2700 MW. The results of this study are shown in figure 7.4. Note that it is only the Strathaven and Eccles

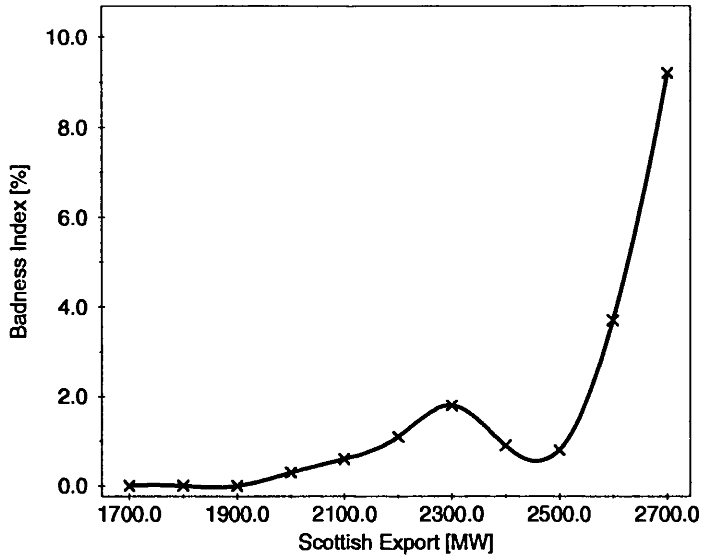


Figure 7.3: Badness index against active power export of the Scottish system with set 'worst case' Scottish generation pattern.

faults which cause significant problems with the set generation pattern.

Figure 7.5 is a graph of the incurred constraint costs against the Scottish export. Above an export of 2200 MW, the constraint cost rises very rapidly. This happens for two reasons. Firstly, the value of the constraints required to restore stability at high exports is correspondingly high. Secondly, the cost of constraint actions rises quickly because expensive out of merit generation is constrained on to replace generation constrained off.

The badness index graph appears to show an anomaly; the study badness at 2400 and 2500 MW export is lower than at 2300 and 2600 MW. The constraint cost at an export of 2500 MW is also lower than at 2400 MW and 2600 MW. The reason for this anomaly is as follows. With a fixed generation pattern in Scotland, the stability of the system is dependant on

```
(C)onstraint (A)nalysis using (M)onte Carlo (E)valuation of (L)oading


CAMEL running ...

5 Monte Carlo re-runs because of failed load flows

Total run time  :        008:46:01
Assessment time :        000:57:41
Constraint time :        007:45:42

Results obtained from 100 simulations of 8 contingencies

Ct.   Name                            %PS    %DI    %BD    %BN +/- L       Cost/yr

   1 Strathaven                       65.0    8.0    2.0   70.0 +/-  8.6  £ 11712k
   2 Eccles                            0.0    6.0    2.0    3.8 +/-  2.7  £   198k
   5 Keadby-West Burton                0.0    0.0    1.0    0.2 +/-  0.3  £     6k
   3 Harker-Hutton                     0.0    0.0    0.0    0.0 +/-  0.0  £     0k
   4 Penwortham-Padiham/Kearsley       0.0    0.0    0.0    0.0 +/-  0.0  £     0k
   6 Deeside-Trawsfynydd-Legacy        0.0    0.0    0.0    0.0 +/-  0.0  £     0k
   7 Cellerhead-Macclesfield-Daines    0.0    0.0    0.0    0.0 +/-  0.0  £     0k
   8 Hinkley Point-Melksham            0.0    0.0    0.0    0.0 +/-  0.0  £     0k

Key:     PS = Pole slip
         DI = Diverging, but no pole slip detected in 12s
         BD = Badly damped
         BN = Badness index for contingency
         L  = 95% Confidence limits of badness index

                        Summary
                        -------

Average badness of study is                  9.2+/-1.5%
Probability of a stability problem is            75.0%
Average constraint cost over study is     £11857.859k/yr
```

Figure 7.4: CAMEL output for a study conducted with set 'worst case' Scottish generation pattern and 2700 MW export.

- the demand in Scotland because this sets the value of the Scottish export,
- the demand on the NGC system because this affects the total required amount of generation, and
- the generation pattern on the NGC system.

Instability therefore occurs because the demand level and generation pattern in the NGC system are problematic. The demand level will be the same for each of the studies, regardless of the Scottish export. However, the generation required on the NGC system will change with different values of export. Now, as the export from Scotland increases, less generation will be needed in the NGC system. The most expensive generation will no longer be in merit and will not be used. It is therefore implied from the studies at 2400 and 2500 MW that generation which is just out

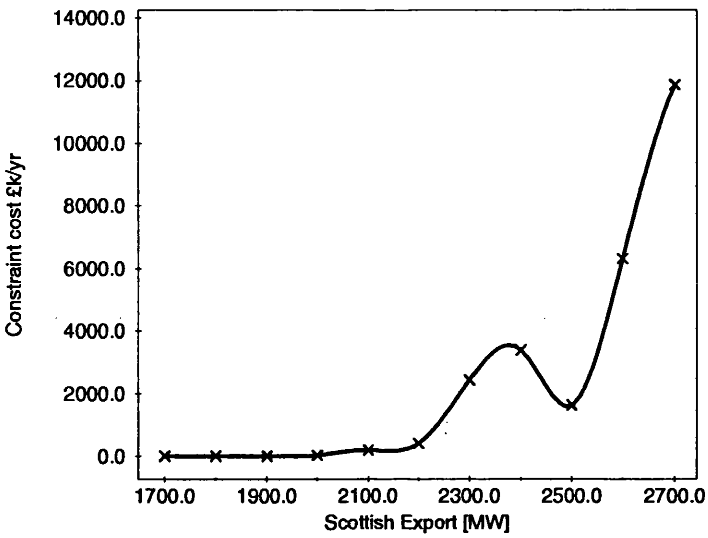


Figure 7.5: Constraint cost against active power export of the Scottish system with set 'worst case' Scottish generation pattern.

of merit is very stability sensitive. Above these values of export, the instability of the system is more a result of the large power transfer from Scotland than onerous generation patterns in the NGC system.

By comparison of the results of the individual probabilistic simulations at export levels of 2300 and 2400 MW, it is possible to identify changes in generation between these two studies which result in instability. Problems occur in two demand ranges: 60-70% ACS and 80-85% ACS. In the 60-70% ACS range, generation increases at KILL83, DEES82, RATS81, COTT81 and FERR81 are associated with a decrease in system stability. In the 80-85% ACS range, it is the increase of generation at DRAX81 and WBUR81 which appears to cause a decrease in system stability.

Export	Export less power flow constraint limit	Maximum constraint found by CAMEL	Constraint saved
2000	90.0	6.2	83.8
2100	190.0	56.2	133.8
2200	290.0	91.2	198.8
2300	390.0	168.4	221.6
2400	490.0	329.8	160.2
2500	590.0	266.6	323.4
2600	690.0	421.0	269.0
2700	790.0	566.2	233.8

Table 7.4: Savings made by the explicit calculation of stability constraints. All values in MW.

7.3.1.1 Performance of explicit stability constraint estimation

Examination of the constraints required to prevent instability allows an important point about the value of the method presented in this thesis to be made. The value of the export from the Scottish system which is consistent with stability of all contingencies for all individual simulations was found to be 1910 MW. In effect, this is the export found with a worst case generation pattern. This is the export limit which would be imposed when using a DC load flow and linear program approach to calculate constraints. However, for some combinations of plant outages and merit order, the best economic operation of the system is achieved by exceeding this value. Using the conventional DC load flow and linear program approach, constraints would be required to reduce the export back to 1910 MW. This result may be contrasted with the performance of the new explicit constraint calculation algorithm contained in CAMEL.

The maximum value of the amount of generation constrained off in the Scottish system for all the CAMEL studies conducted above is listed in column 3 of table 7.4.

Column 4 is the difference between the constraint required for each simulation if a power flow limit of 1910 MW were imposed, and the maximum value of the constraint required to restore stability found explicitly. For an export of 2000 MW, the maximum constraint required is a mere 6.2 MW, compared with the 90 MW of constraints which would be required to obey the power flow export limit of 1910 MW. In other words, by CAMEL selecting the best generation to constrain off, 83.8 MW of constraints may be saved, resulting in significantly reduced cost.

It should also be noted that constraints are only required in 4% of cases at an export of 2000 MW. At all other times, the export of 2000 MW is stable. However, the conventional approach to estimating constraint costs would impose the DC limit of 1910 MW in all cases. Thus, constraints of 90 MW would be needlessly imposed in 96% of cases, at considerable extra cost.

This example therefore illustrates how CAMEL is able to make a far more accurate estimation of stability constraint costs by calculating them explicitly for each simulation.

7.3.2 Case 2: Scottish generation included in the pool

In this case, the generation in the Scottish system is included in the NGC pool system. Each Scottish generation unit has its own pool offer price as shown in appendix table D.3. Scottish generation may also be affected by outages. The availabilities that were used for these studies may be found in appendix table D.2.

This case study is more realistic than that presented in section 7.3.1 because the Scottish generation pattern and export are allowed to vary in the manner which would occur on the real system. However, a series of CAMEL studies were run with the maximum export from Scotland restricted to a set value. The imposition of such

Export (MW)	Probability of a stability problem (%)	Probability of excess export (%)	Average demand of bad simulations % ACS	Study badness ± conf. int. (%)	Constraint costs £k/yr
1700	2.0	56	61.0	0.0±0.1	5.08
1800	3.0	55	63.4	0.2±0.3	7.81
1900	3.0	53	63.4	0.2±0.3	7.81
2000	3.0	49	63.4	0.2±0.3	7.81
2100	7.0	46	65.6	0.4±0.5	67.0
2200	8.0	45	67.8	0.5±0.6	168
2300	12.0	43	68.1	0.9±0.8	422
2400	13.0	42	69.4	0.9±0.8	461
2500	15.0	40	70.0	1.0±0.8	953
2600	18.0	35	71.6	1.3±1.0	1,470
2700	23.0	31	72.9	1.9±1.2	2,630

Table 7.5: Table of badness index and constraint cost for a set of CAMEL studies performed at different values of Scottish export. Scottish demand and generation were included in the probabilistic simulation.

a restriction might be necessary for thermal reasons, say. The main purpose of this case study is to find the constraint costs for different values of export restriction and compare these with the results of the previous case study.

The results of the CAMEL studies are shown in table 7.5.

Column 3 of table 7.5 shows the proportion of probabilistic simulations which were 'scrapped' because the export limit, shown in column 1, was exceeded. When this occurred, new probabilistic simulations were automatically run until a scenario was generated for which the export is less than the imposed limit. This process is explained in more detail in section 6.6.

From the figures in column 3, it can be seen that constraints would be necessary 56% of the time if the export were limited to 1700 MW. This is primarily a function of the position of the Scottish generation in the merit order. The selection of a different merit order would doubtless give different results as implied by the case study presented in section 7.3.4.

The gradual increase in the demand level at which stability problems occur, shown in column 4, reflects the fact that the average demand level for each study will increase as the export limit is relaxed. This can also be interpreted as the export from Scotland increasing as the demand on the system increases. The reason for this is that the system's merit order dictates that the generation in Scotland is used when the overall demand on the system is high.

Studies were performed at export levels below 1700 MW to find the value of export consistent with the stability of all contingencies. This was found to be 1450 MW. The fact that this value of export is considerably lower than that found using the set generation pattern in case study 1 suggests that the set pattern is not the 'worst case' at low export levels.

The probability of a stability problem in the CAMEL studies conducted in this section is consistently lower than the corresponding probabilities for the previous case study. This is expected because the generation pattern in the system will contrive to cause instability far less often than when the generation pattern in Scotland is set to an onerous scenario for all simulations. The constraint costs are also lower and more realistic for the same reason. These costs are compared with the constraint costs for case study 1 in figure 7.6.

7.3.3 Case 3: Loss of the Lackenby-Thornton transmission line

The purpose of this case study is to show how CAMEL might be used to make comparisons between different network topologies. A double circuit transmission

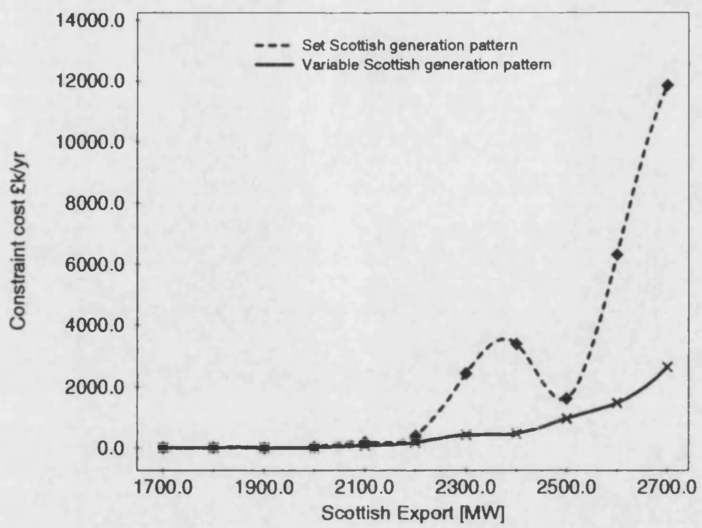


Figure 7.6: Constraint cost against active power export of the Scottish system with set and varied Scottish generation patterns.

line between Lackenby and Thornton has been removed from the base transmission network. The rest of the conditions for the CAMEL studies remained the same as those for the results presented in the previous case study. This allows direct comparisons between the constraint costs for the two networks to be made.

Because the system has been weakened by the removal of a transmission line, a new contingency sequence has been introduced for this case study. With the removal of the Lackenby-Thornton transmission line, the fault on the Norton-Osbaldwick/Thornton double circuit becomes critical. The fault location is shown highlighted in figure 7.1, while the corresponding contingency sequence is shown in figure 7.7.

The results of 8 CAMEL studies conducted are shown in table 7.6. The constraint costs at different values of export are compared with the corresponding results for case study 2 in figure 7.8. From this comparison, it is possible to make quantitative judgements about the constraint costs saved by the existence of a line between

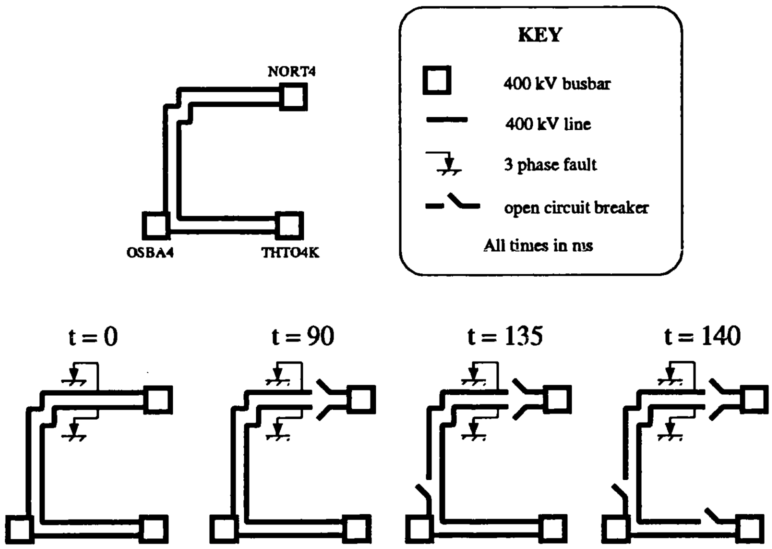


Figure 7.7: Norton-Osbaldwick/Thornton contingency sequence

Lackenby and Thornton which could be weighed against the cost of building the line. For example, at an export of 2200 MW, say, the line is 'worth' about £10.7m/year (£10.9m−£168k) in saved constraint costs.

Clearly, the constraint costs for this network are far higher than the reinforced network. This is predominately due to the frequent instability of the Norton-Osbaldwick/Thornton contingency sequence when the line between Lackenby and Thornton is removed. Quite severe constraint actions are occasionally necessary to secure this contingency.

The results of this case study appear to present a pessimistic picture of the stability of the present NGC system as the line between Lackenby and Thornton is yet to be built. However, the stability of the actual system is preserved by a fast stability intertrip on the Teeside generation units located to the north of Norton at Greystones.

Thorough examination of the constraints required to secure individual simulations show that the reduction of generation at Saltholme, Hartlepool, or Greystones is the solution determined by CAMEL for stabilising the system for the Norton-

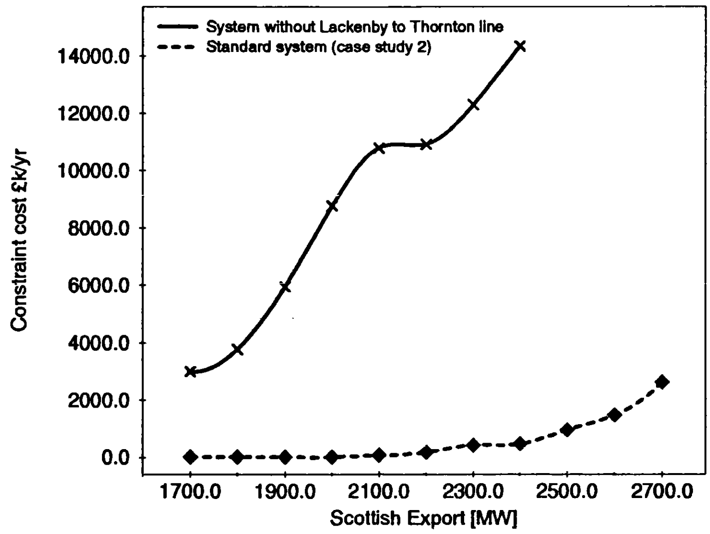


Figure 7.8: Constraint cost against active power export of the Scottish system with and without the Lackenby to Thornton line included in the NGC system.

Osbaldwick/Thornton contingency. This result is consistent with the use of the intertrip scheme mentioned.

7.3.4 Case 4: Change in the merit order

This case study has been included to highlight the important part that the economic background to a study may play in the stability of the system. In turn, this shows how the technique of including a crude economic model into the software reduces the problem space, allowing the power system planner to focus in on the stability constraints which are of particular relevance, given the economic pretext.

Ten CAMEL studies have been run with the pool offer prices determined randomly for each generation group at the beginning each study. These are shown in appendix table D.4. The export from the Scottish system was not restricted for these studies. The results of the ten studies are shown in table 7.7. Constraint costs have not

Export (MW)	Probability of a stability problem (%)	Probability of excess export (%)	Average demand of bad simulations % ACS	Study badness ± conf. int. (%)	Constraint costs £k/yr
1700	12.0	56	57.2	1.4±0.8	2,990
1800	14.0	55	61.3	1.7±1.0	3,770
1900	17.0	53	62.6	2.0±1.1	5,940
2000	20.0	49	63.0	2.4±1.1	8,770
2100	24.0	46	64.6	3.1±1.4	10,800
2200	25.0	45	65.4	3.1±1.4	10,900
2300	28.0	43	66.1	3.8±1.7	12,300
2400	28.0	42	66.3	3.8±1.7	14,400

Table 7.6: Table of constraint costs and badness for a set of CAMEL studies conducted on a transmission network without a transmission line between Lackenby and Thornton.

been calculated for these studies because the pool offer prices are not real and would therefore yield unrepresentative constraint costs.

For comparison, a single CAMEL study was run using the standard merit order given in appendix table D.3. The results for this study are also included in table 7.7.

The apparent stability of the system is very much affected by the positions of generation units in the merit order, with different merit orders giving quite diverse results.

As would be expected, high values of Scottish export, such as studies 'random 8' and 'random 10' lead to more stability problems. Note that it is the *average* value of power export which is quoted in column 2 of table 7.7. Obviously, the export will be considerably higher than the average value in some individual probabilistic simulations and when stability problems do occur, they are generally at exports above the average level.

Study	Average value of Scottish export (MW)	Probability of a stability problem (%)	Average demand of bad simulations	Study badness ± conf. int. (%)
random 1	1006	4	75.4	0.4 ± 0.5
random 2	-399	0	-	0.0 ± 0.0
random 3	950	3	47.9	0.3 ± 0.3
random 4	1140	12	70.1	1.5 ± 0.8
random 5	1897	32	58.5	5.4 ± 2.3
random 6	194	0	-	0.0 ± 0.0
random 7	132	0	-	0.0 ± 0.0
random 8	2017	46	58.2	7.3 ± 2.4
random 9	-191	0	-	0.0 ± 0.0
random 10	1949	25	63.4	3.4 ± 1.6
standard	1275	43	76.7	10.1 ± 3.3

Table 7.7: Table of results for a set of CAMEL studies using ten randomly selected merit orders and the standard merit order.

It should be clear that these studies are unrealistic. The generation in operation at any demand level will tend to be far more evenly distributed across the system than would be the case in practice. For example, generation in the North East of England is often in merit on the real system, whereas it will only have an even chance of being in merit when pool prices are set randomly. Thus, stresses which occur on the real system because of economic factors will not be portrayed with randomly selected pool prices. This explains the fact that the stability of the system using the standard merit order is worse than that of the random merit studies.

Because the apparent stability of the system is so dependant on the generation merit order, it is suggested that several studies are run with different merit orders to represent any uncertainty in the pool offer price of each generation unit. Alternatively, CAMEL could be modified to use several merit orders, or even model pool prices using a probability distribution. This topic is discussed further in section 8.1.

Chapter Eight

Further Work

8.1 Enhancements to the probabilistic model

Generation pool offer prices are known to vary considerably over an operating period. This is a natural function of the competition present in the electricity pool system. However, CAMEL presently only uses one merit order within a study run. While it is possible to divide a typical year of operation into several parts and run a separate CAMEL study on each with a different merit order, this is somewhat laborious. The ability to use several merit orders could easily be included into CAMEL to overcome this. Alternatively, a probabilistic distribution could be used to model the offer price of each generation group, as suggested in figure 8.1. Although quite trivial to implement, such a feature would be difficult to utilise because of the availability of data.

Despite the reservations stated in section 6.4.2, it may be beneficial to include maintenance transmission outages in the Monte Carlo simulation. Maintenance plans are usually available several years in advance, and, although they are subject to change, to ignore them altogether may give an optimistic picture of constraint costs. The problem with maintenance outages is that they must be coordinated in such a

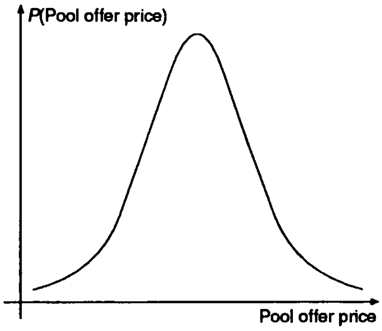


Figure 8.1: Pool offer price variation for an arbitrary generation group.

way that certain concurrent outages, which system planners would not permit, are prevented from occurring. The use of expert systems seems to provide the most promise in this area [107].

Forced transmission outages would be more easily included into the Monte Carlo simulation, although, because they occur very infrequently and sporadically, it is difficult to obtain accurate statistical availabilities for specific items of plant.

8.2 Constraint algorithm

A major part of the constraint algorithm is the quantitative stability method used to perform linear sensitivity analysis at a given operating point and rank the generation groups in the system according to their stability sensitivity. Improvements to the quantitative stability method presently used in the constraint algorithm are considered below. The development of this method was motivated by the impracticality and limited performance of existing methods. Further developments in this area are discussed in section 8.2.2.

8.2.1 Improvements to the new quantitative stability method

Improvements to the method described in chapter 5 can be considered in three main areas; the use of more data samples during the selection of composite indices, the use of better data for selecting composite indices, and the use of an ANN for providing a stability index. These are discussed below.

8.2.1.1 Selection of composite indices

Presently the selection of a suitable set of composite indices is only made with a small list of pertinent, or onerous contingencies. The selection can also only be made at one system operating point. Both of these restrictions are caused by the present design of the composite index selection software, rather than any limitations of the method. A re-implementation of the software, which allows the temporary storage of selection data on disk, instead of memory, would eliminate this problem.

The selection of a set of composite indices based on a broader range of operating conditions would potentially improve the performance of the method. It is also possible that the generality of the indices would extend to other power networks without the need for re-selection.

8.2.1.2 Alternative to time domain data

Some of the problems with the time domain constraint evaluation data used during the selection of composite indices have been highlighted in chapter 5. In particular, it is not possible to find constraints for generation groups which, although very stability sensitive, do not have an active output large enough to result in system stability when fully constrained off. Sensitivity of critical clearing time (CCT) is the best method for overcoming this problem. An added advantage of this method is that the same change in generation can be used when calculating the sensitivity of CCTs and composite indices. This decouples the problematic effects of differing changes in slack generation in the system, which occurs when finding constraints, as described in section 5.2.1. However, calculating CCT sensitivities is prohibitively slow. The cautionary remarks made below in section 8.2.2 are also appropriate here.

8.2.1.3 Addition of an ANN

If sufficient time domain constraint data is generated, an ANN could be trained to produce a stability index specially suited to this application. The advantage of this is that the ANN would be able to perform a non-linear mapping which should enhance the accuracy of the results obtained with the new quantitative stability method. It is however expected that the ANN would need to be trained using the constraint results from thousands of contingencies rather than tens of contingencies used during this work. The computing time taken to generate the time domain data would be hundreds to thousands of hours.

An alternative would be to train an ANN to produce an energy margin as its output. However, accurate training data would be difficult to obtain since even hybrid TEF does not compare especially well with time domain results.

8.2.2 Replacement of the new quantitative stability method

When further large increments in computing power are realised, the use of CCT sensitivities to select generation groups to constrain should be considered. It is generally accepted that the CCT is the best relative measure of power system transient stability, since if the CCT for a contingency can be increased above the time taken for protection systems to clear the fault, the system will be stable. Hence, rather than using the sensitivity of system energy margin, or a set of pertinent indices, sensitivity of the CCT could be used to select the best generation groups to constrain to restore security. At present, this approach is impractical because of the time taken to evaluate CCTs to a sufficient accuracy. Even for quite large changes in the output of a generating group, a contingency's CCT may only change by a few milliseconds. Thus, the simulation integration time step must be significantly reduced to obtain the required levels of definition.

In some respects, it is appealing to use either the CCT or a direct method because both provide a stability margin which should enable calculation of the size of generation changes required to reach a stable operating condition. In practice, linear extrapolations of this kind are inaccurate because the system stability domain is non-linear for anything other than small generation changes. The algorithms presented in this thesis are designed to cope with such effects, but would still benefit from improved selection and ranking of stability sensitive generation. Direct methods may yet yield this information, although this research field has been active for several decades without providing methods as accurate as time domain simulation. Adequate approaches to subsequent swing instability are also yet to be formulated.

8.2.3 Solution for multiple contingencies

The amalgamation of constraint actions for multiple contingencies, described in section 6.8.2, works for two reasons:-

① The assumption is made that all contingencies may be secured simultaneously, which is reasonable for properly designed power systems.

② Constraint sets do not tend to conflict because nearly all the generation in the system is fully loaded. Thus, a generation group will not be constrained on for one contingency and constrained off for another, unless it is the marginal group.

However, although this approach generally results in a secure operating condition, no attempt is made to determine which constraint sets are redundant in the final amalgamated schedule. Thus, excess constraint costs may be encountered in these cases. A straight-forward way of removing some of this redundancy would be to apply the constraints required for one contingency and then test the stability of all the others. The constraint algorithm would then find a set of constraints for the next unstable contingency encountered and test all other contingencies again. This process would continue until all contingencies are secure. Clearly this process is iterative in nature and therefore was not selected for this work because of the computational overhead.

8.3 Thermal and voltage constraints

The use of a DC load flow and linear program to enforce thermal limits has already been well proven elsewhere [24, 38]. It is envisaged that if CAMEL is to be extended to include thermal constraints, similar techniques would be employed.

Other techniques would be required to evaluate voltage constraints explicitly. Previous work by the author has shown that expert systems may be used to dispatch reactive controls in order to regulate system voltage levels [111]. Others have combined analytical sensitivity analysis and fuzzy expert systems to perform this task [36, 112]. Of course, if reactive controls are used alone, no constraint costs are incurred. In the future this situation may change since a reactive market is soon to be instigated in the UK [113].

If thermal, voltage and stability constraints are enforced sequentially, it is possible that the imposition of stability constraints may cause new voltage security violations. Likewise, thermal security violations may be caused by voltage constraints. Hence, some intelligent restriction of the controls used to satisfy constraints at each stage would be necessary. Alternatively, an integrated approach to making thermal, voltage and stability constraints could be taken.

8.4 Parallel tasking

The CAMEL master task runs many individual probabilistic simulations. Because each of these simulations can be considered as a separable task, the CAMEL software is well suited to parallelisation across a number of computers. There is no need for these computers to have the same architecture, or even run the same operating system, provided they are able to communicate with each other. In the experience of the author, the *Parallel Virtual Machine* (PVM) [29] software provides the ideal mechanism for such parallelisation.

Transient stability assessment is made during each individual probabilistic simulation using *PowSim Engine* (PSE). This task may be easily parallelised at the contingency level. In fact, PSE supports the use of several processors connected to the same memory bus within a single PC. It can therefore utilise the new range of multi-processor Pentium Pro-based PCs running under a Unix operating system. Therefore, this provides a convenient means for parallelising the stability assessment task. A possible configuration is given in figure 8.2.

Evaluation of constraints is part of an individual probabilistic simulation and

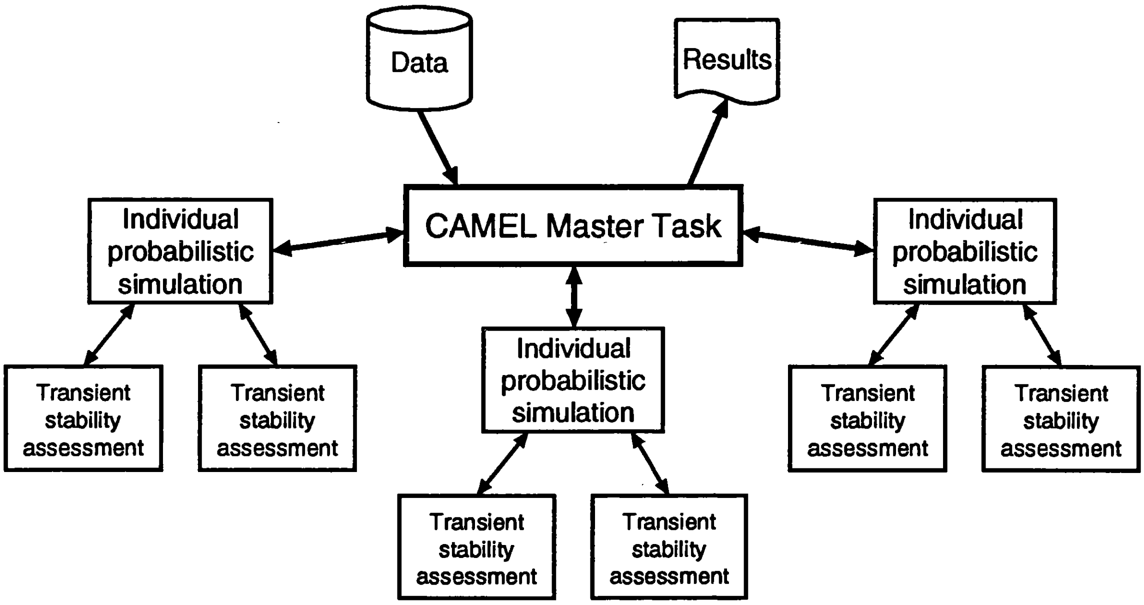


Figure 8.2: Parallel implementation of the CAMEL software, using PVM and dual processor architecture machines.

parallelisation at this level is possible, as has been described above. However, parallelisation of the constituent steps of the constraint algorithm requires some thought since the algorithm is presently designed for sequential processing. The sensitivity analysis can certainly be parallelised because the effect of perturbations of each generation group can be tested separately. Single generation group constraint possibilities could also be tested on any available processors. Some of the results of these tests may be discarded later if they do not form part of the algorithm's 'critical path' to a least cost set of constraints. However, should the results prove relevant, their use will save solution time. The evaluation of low cost single generation group constraints in parallel with the smallest power constraints is illustrated in figure 8.3.

8.5 On-line applications

It has been shown in section 7.3.1.1 that the use of DC power flow limits can be conservative and may result in needless constraints. For the reduced costs

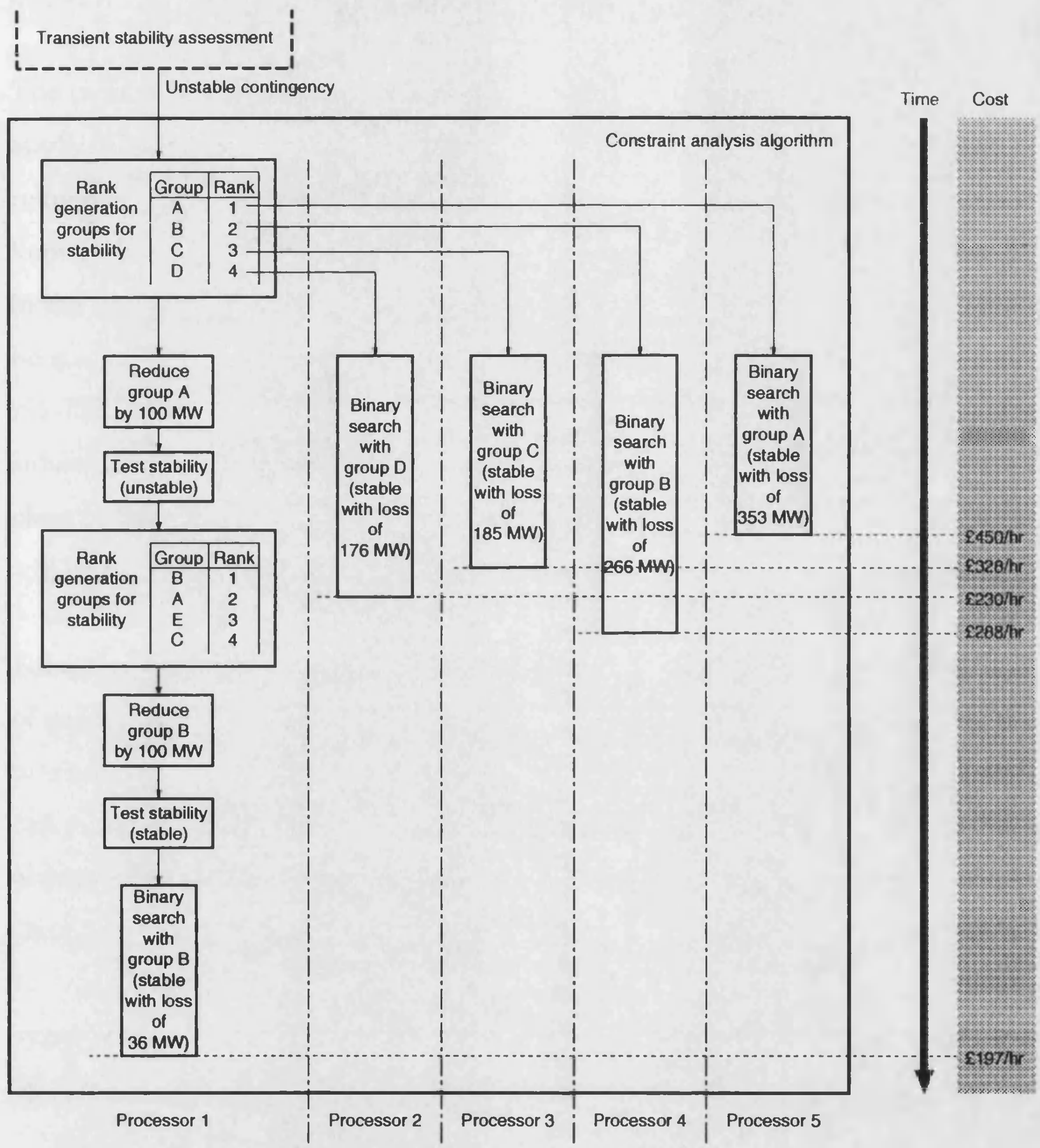


Figure 8.3: Parallel implementation of the constraint algorithm, also suitable for on-line application. In this case, a single generation group constraint is found first with group A, while the lowest cost constraints are subsequently found with groups A and B. Note that the corresponding constrain-on actions are not shown in this figure.

observed with the explicit constraint estimation method to be realised during on-line operation, similar techniques must be adopted in the control room.

The methods used to evaluate constraint actions presented in this thesis are equally applicable in an on-line environment. In fact, the problem space is considerably reduced on-line. The system generation and demand pattern are obviously already known. Furthermore, system operators will have a good idea which generation groups in the system are candidates to be constrained on a given day. Selection will not only be governed by the pool offer prices and location, but also knowledge of run-up and run-down times. The constraint algorithm may therefore operate on a much reduced subset of generation. In addition, if the system is insecure, it should still be very close to the stable operating region. Thus, the size of the constraint actions required will be small. In this case, the constraint algorithm will reach a solution quickly.

For a single contingency, the constraint algorithm initially finds the minimum amount of generation that must be constrained to restore stability. This information may be presented to the system operator as soon as it is available, after which the algorithm can explore other possible lower cost constraint actions. Thus the operator would be able to make the system secure as soon as possible, or take the small risk of operating the system insecurely until the lowest cost solution is found. If the parallelisation techniques discussed above are applied to the constraint algorithm, information on successful single generation group constraints could also be made available to the operator very rapidly, and while a lower cost solution is still being sought.

Chapter Nine

Conclusions

The power transport capability of modern power systems is increasingly becoming restricted by the requirement to maintain transient security. New interconnections between power systems and changes in economic climate have placed more stress on transmission systems. There is a need both to better utilise existing capability and to remain flexible in the event of long term changes in generation and demand.

Privatisation of power systems, particularly in the UK, has brought new pressures to bear upon power system planners. Generation companies will wish to connect new plant to the transmission system, and the impact of this new generation on the system must be assessed within a few months. In certain situations, the proposed connection may have far-reaching implications. Given the tight time scales and potential uncertainties in the future system, the planner may be ill-equipped to thoroughly analyse the proposal using conventional deterministic planning methods. Instead, utilities are now turning to probabilistic approaches to planning in order to model future uncertainty and diversity in the operation of the system.

Power systems should be planned such that avoidable operational costs are minimised, without compromising the security of the system. A large component of operational costs results from the inability to use the most cost effective generation systems because of transmission system limitations, or constraints. In modern power systems, an increasing proportion of the associated constraint cost is caused by system transient stability limitations. An appreciation of this cost is very useful to the power system planner because this helps to facilitate cost-benefit evaluation of transmission system reinforcement.

Previously, transient stability constraint costs have been evaluated within the framework of a DC load flow and linear program. To facilitate this it has been necessary to impose DC power flow limits across key system boundaries. Unfortunately, the DC limits are calculated outside the main program using a transient stability analysis package and a worst case scenario. The conservatism which this approach implies leads to the over-estimation of constraint costs, encouraging planners to make needless investment in the transmission system.

The main aim of the work described in this thesis is the *explicit* estimation of the constraint costs caused by stability limitations. To do this, a probabilistic model of system operation has been built. The stability of the system may then be tested at a large number of different, but likely, system operating points. Finally, in the event of transiently insecure scenarios, a special constraint algorithm is used to select the most cost effective generation groups in the system to constrain to restore system stability. Thus the cost of these actions may be measured directly. The cost estimates formulated enable power system planners to make better informed judgements about the merits of changes in the transmission system.

The means by which the initial aim of this work has been fully met are laid out below.

9.1 Probabilistic model of system operation

A probabilistic model of the operation of a power system has been built for this work. This is used to generate possible power system operating conditions. A Monte Carlo simulation is used to model generation plant outages, while an appropriate system demand is selected probabilistically from a set of load duration curves. Available generation is scheduled to meet system demand according to merit order.

Appropriate techniques have been adopted at each stage which reflect the quality and accessibility of relevant data. For example, the probabilities of forced and planned generation outages are combined to form single availabilities. Of course, one of the advantages of the probabilistic model used for this work, is the ease with which enhancements may be made. In the event that more comprehensive data is available in the future, some modifications could be considered. These were discussed in section 8.1.

This simulation generates system operating points which are not only possible, but *likely.* The elegance of this approach is that the large operating space of the system is immediately reduced to the area of interest. The scenarios generated at this stage are then passed on for full security assessment, after which constraint actions will be implemented if necessary.

9.2 Security assessment

Transient security assessment is made using a fast time domain simulator. Transiently insecure contingencies are automatically identified and classified by analysis of generation group rotor angle curves. The speed of the time domain simulator enables security assessment to be made very quickly without the need for direct stability methods which could potentially sacrifice accuracy. All power system components can also be faithfully represented.

The probabilistic generation and stability assessment of a set of operating points may uncover stability problems that could be missed during a conventional deterministic analysis. The observation of stability problems at a low value of Scottish export during case study 2 in section 7.3.2 demonstrates this. Thus, the ability to perform a 'stability survey' across a broad range of operating conditions can therefore be seen as a useful additional benefit of this work. Stability surveys can be completed in as little as 1-2 hours for a realistically sized system.

To aid the rapid interpretation of the results from a stability survey, a 'badness index' has been devised. This is an empirical measure of the system's stability based on the probabilities of each contingency analysed causing stability problems. Monitoring the index during the course of a CAMEL study allows for early termination if the stability of the system is above or below user defined tolerances. Computational time is thereby saved.

9.3 Constraint cost evaluation

While stability surveys are useful for rapidly determining the stability of a power system across a broad range of likely operating conditions, the aim of this work has been to provide constraint cost information. After all, a contingency may only prove to be insecure in a small number of cases, but the cost of the constraint actions required to restore the security of the system may be unacceptably high.

An algorithm has been developed which is able to perform the explicit calculation of stability constraint costs. To meet the requirements of this algorithm, it was necessary to devise a new quantitative stability method, which is discussed below. The constraint algorithm has also been designed to exploit properties of the system's generation to find a low cost set of constraints with very reasonable computational effort. Realistic constraint actions are implemented by the algorithm and constraint costs are thus found directly. All constraint actions are tested using time domain simulation to ensure that system security had been restored.

Results obtained with the algorithm were presented in chapter 7. Section 7.3.1.1, in particular, makes an important comparison between the performance of the constraint algorithm described in this thesis, and the DC power flow limit approach conventionally used. In summary, the selection of the most cost effective generation groups to constraint to restore transient stability makes considerable constraint cost savings over the imposition of DC power flow limits. This is because the stability of the system is related more to the output of individual generation groups, rather than power flows across 'critical' boundaries.

Unfortunately, the DC power flow limit method is more consistent with current on-line operational practices in the UK. Transfer limits are calculated off-line using a worst case scenario. Not only is this approach conservative in most cases, but it does not ensure system security when operating conditions deviate beyond the scenarios used for off-line studies. On-going work at the University of Bath [28, 30] is aimed at the use of Dynamic Security Assessment techniques to alleviate the need for on-line DC power flow limits. The adaptation of the work described in this thesis for on-line use was also discussed in chapter 8.

9.4 New quantitative stability method

Direct stability methods provide quantitative information about the transient stability of a power system, i.e. as well as finding the system's absolute stability, they are also able to assess how stable, or unstable, the system is. This information proves to be invaluable if system security is to be restored in practical time scales.

A comprehensive review of 'classical' quantitative stability methods was presented in chapter 4. The conclusion of this review was that these methods are not sufficiently general or reliable to be used for this work. Their inability to deal with subsequent swing transient instability was a significant factor here.

A new quantitative stability method was devised and tailored to fit into the constraint algorithm used in CAMEL. The key requirement was that the method should be capable of ranking the generation groups in the system by their ability to increase system stability for the smallest change in active output power.

The method is an involved adaptation of some of the techniques used for transient stability screening with artificial neural networks. In common with that work, though, the new quantitative stability method requires some 'off-line' configuring. However, results obtained with the new method are comparable with state-of-the-art direct stability methods for first swing instability. In addition, the method is able to produce very acceptable results for subsequent swing instability and damping problems too. The new method is also very fast as time domain simulation is only needed up until the end of the contingency sequence, after which simple statistical processes are used to calculate the results.

9.5 Summary

This work has looked in detail at the areas of probabilistic power system planning and power system transient stability. A method has been devised for making accurate estimates of transient stability constraint costs. It has been shown that this method alleviates the degree of conservatism apparent in previous approaches to this problem. Hopefully the refinement of these techniques, and possibly their adoption for on-line stability constraint management, may lead to better planned and operated power systems in the future.

Appendix A

Contingencies

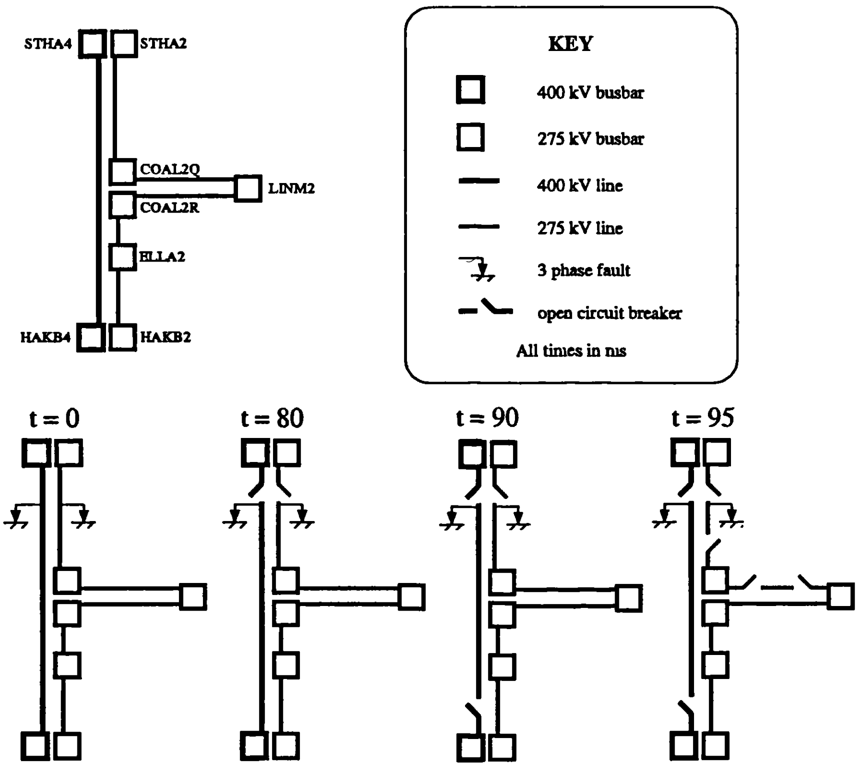


Figure A.1: Strathaven contingency sequence

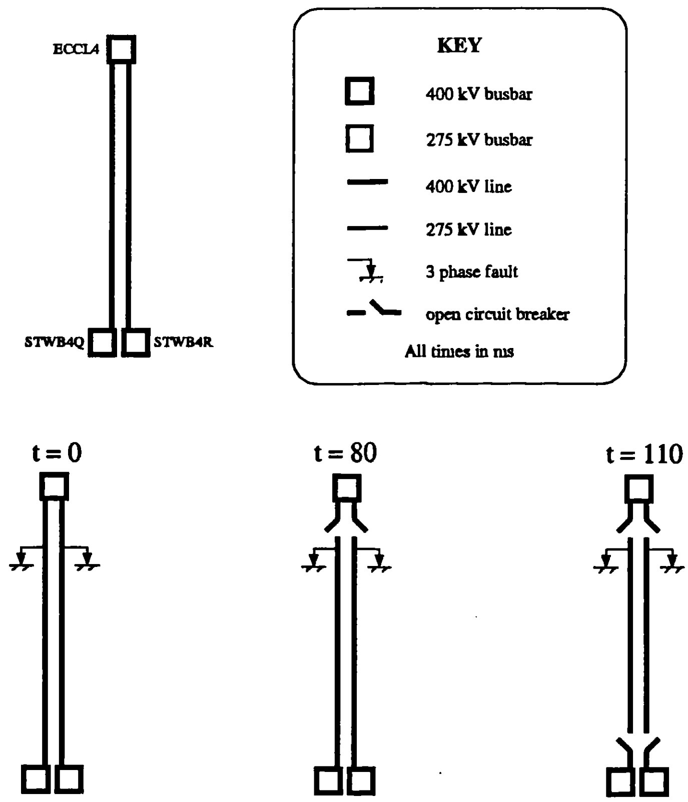


Figure A.2: Eccles contingency sequence

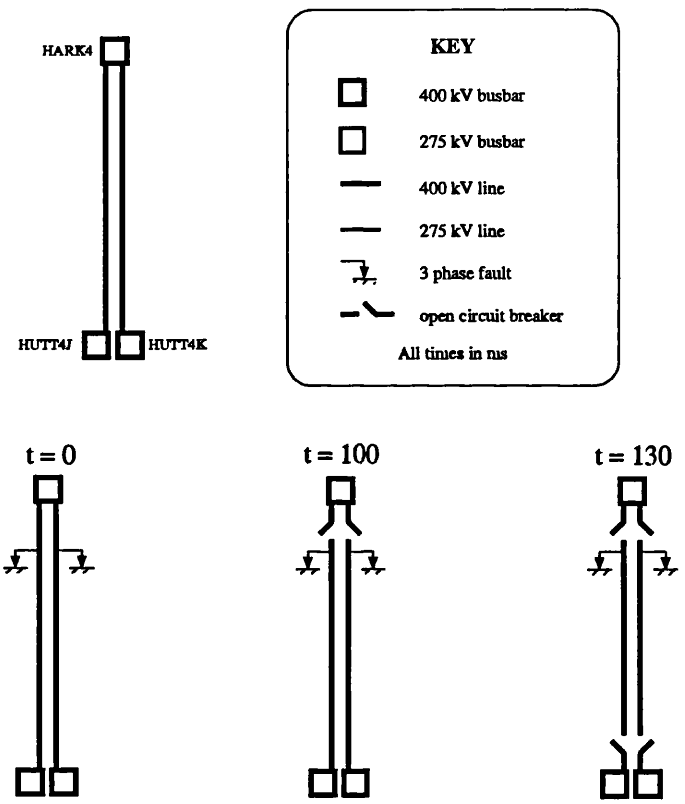


Figure A.3: Harker-Hutton contingency sequence

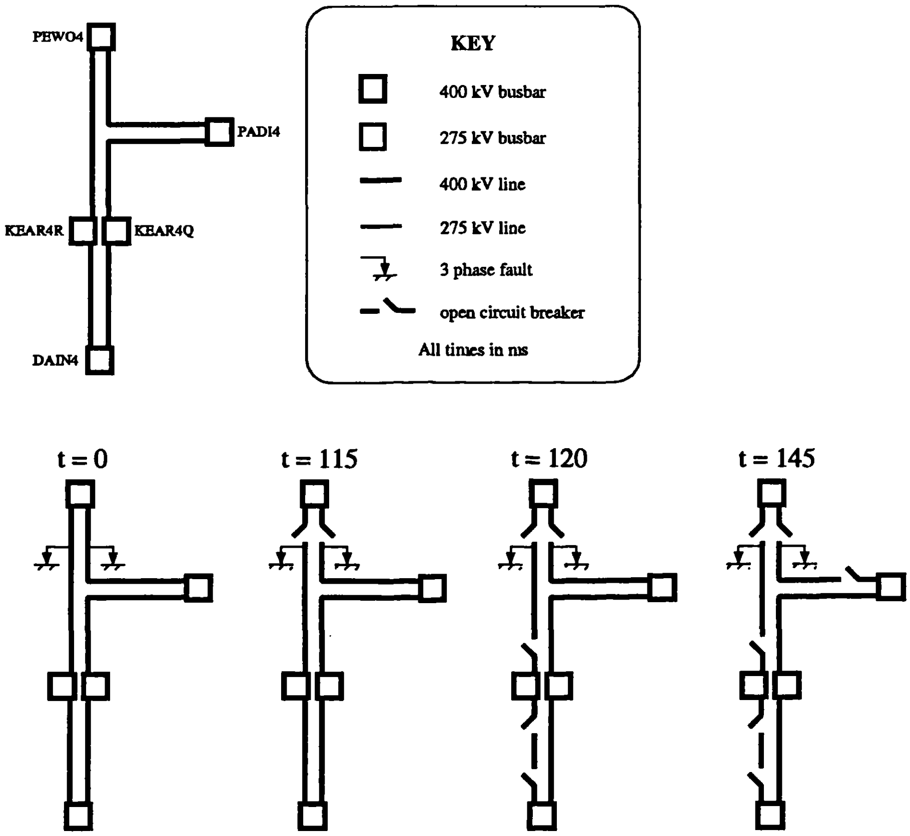


Figure A.4: Penwortham-Padiham/Kearsley contingency sequence

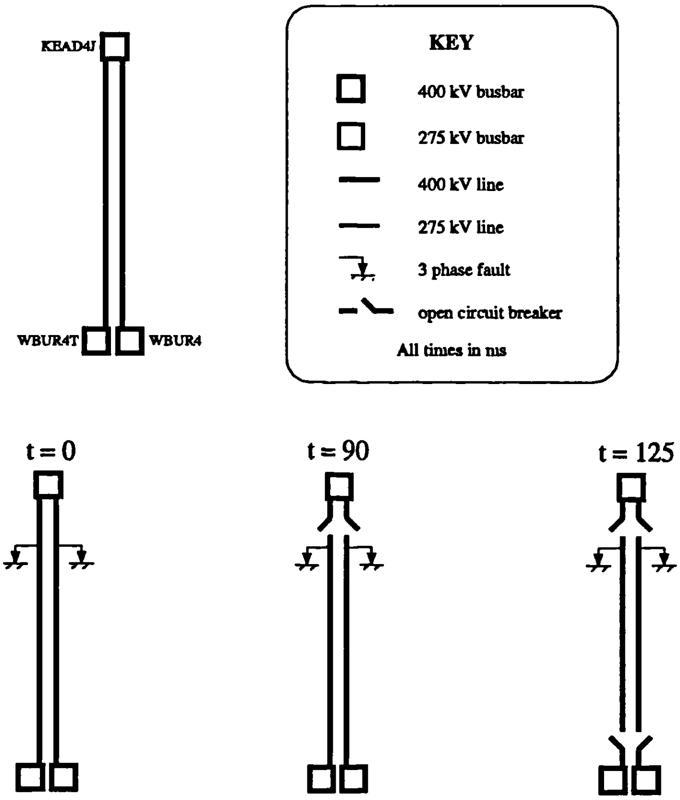


Figure A.5: Keadby-West Burton contingency sequence

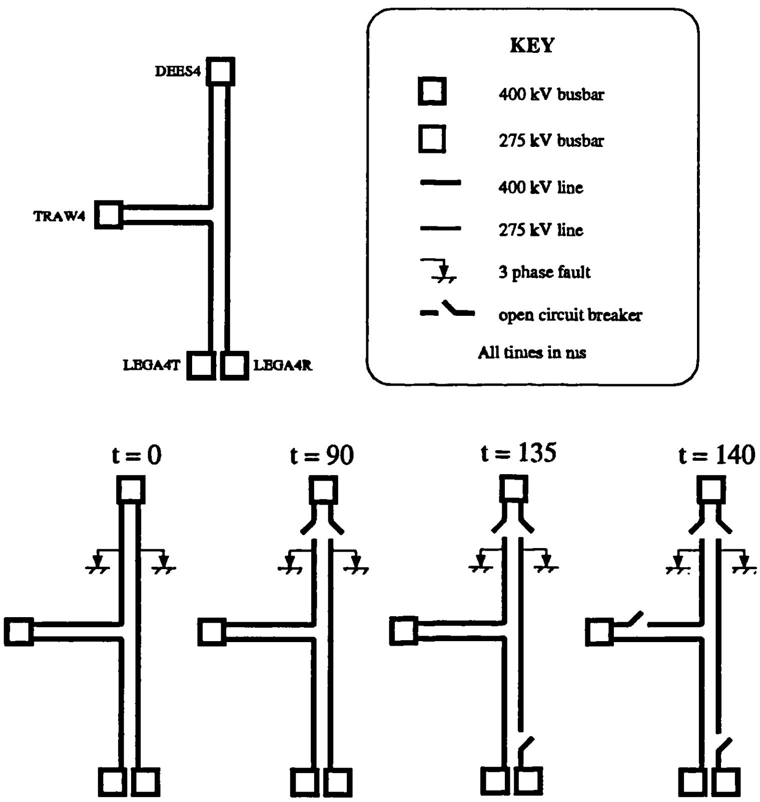


Figure A.6: Deeside-Trawsfynydd-Legacy contingency sequence

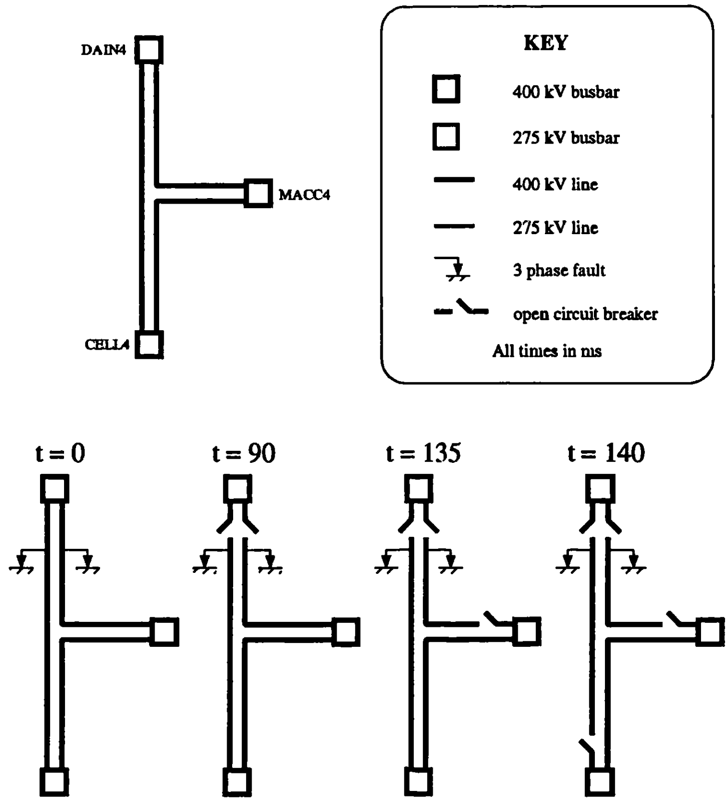


Figure A.7: Cellerhead-Macclesfield-Daines contingency sequence

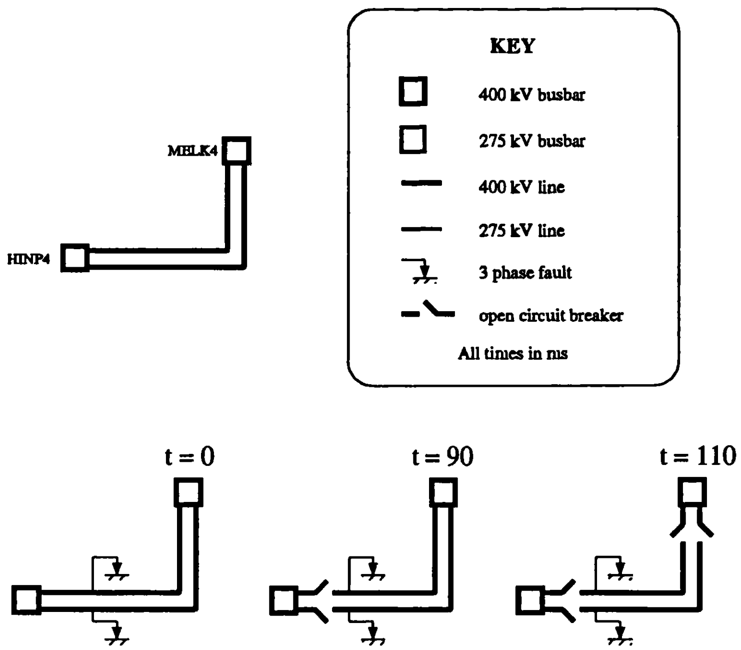


Figure A.8: Hinkley Point-Melksham contingency sequence

Appendix B

Composite index selection for first swing instability

The rotor angle plots in figures B.1- B.8 show the generation groups participating in the system mode of disturbance for the set of eight contingencies given in figures A.1-A.8. In some cases, not all the groups participating have been plotted. This has been done to keep the plots uncluttered. The groups that are not shown have trajectories very similar to other groups which have actually been plotted.

All the plots were obtained using PSE, and a fault clearing time slightly greater than the critical clearing time for each contingency was used. The plots correspond to the set of first swing unstable contingencies used during composite index selection, yielding the results in tables B.1- B.8

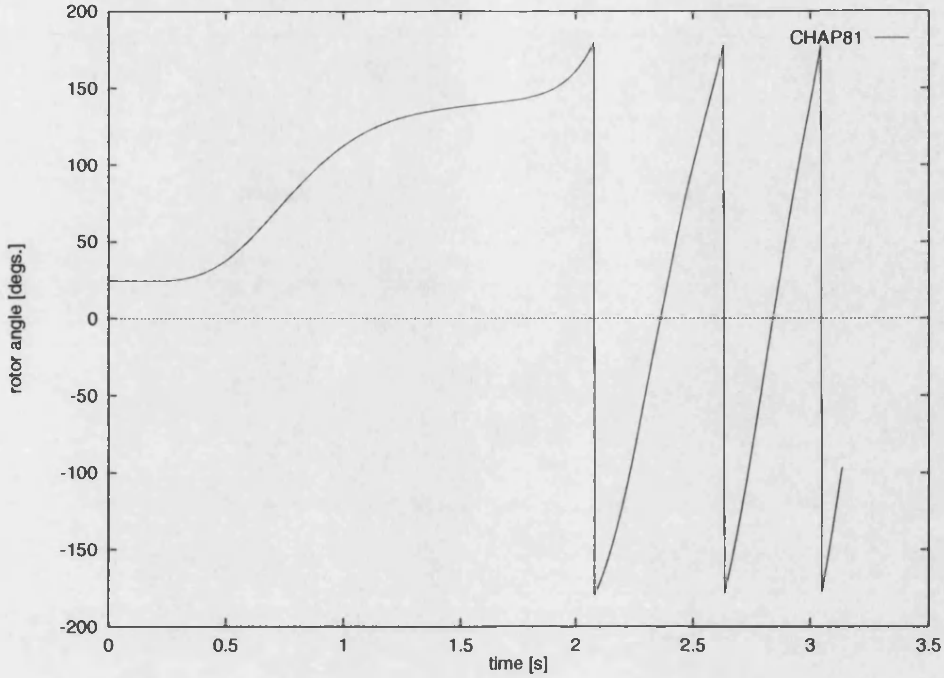


Figure B.1: A rotor angle vs time plot for the Strathaven first swing unstable contingency obtained using PSE.

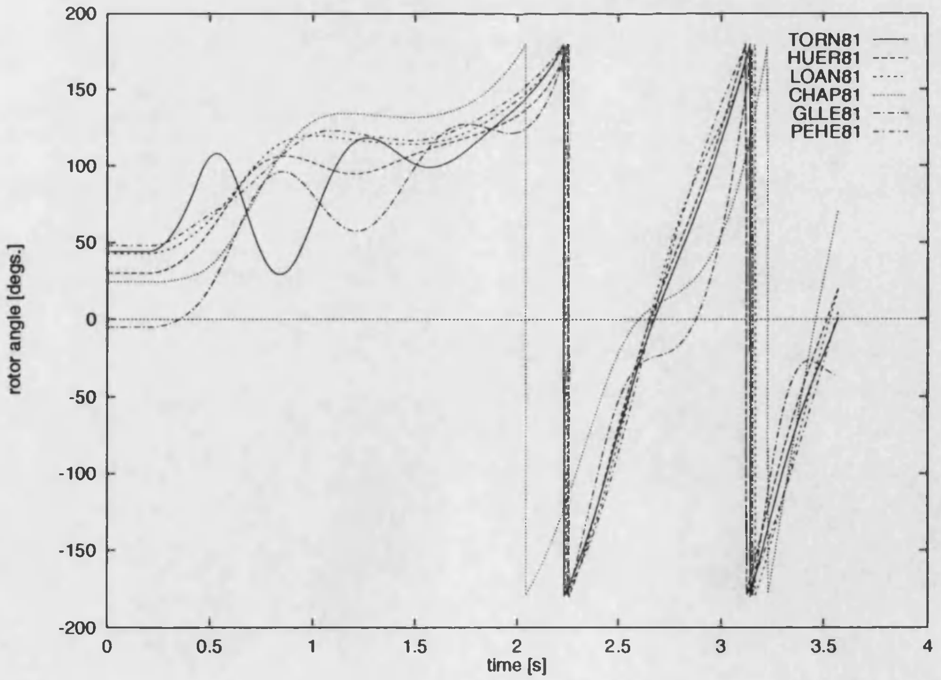


Figure B.2: A rotor angle vs time plot for the Eccles first swing unstable contingency obtained using PSE.

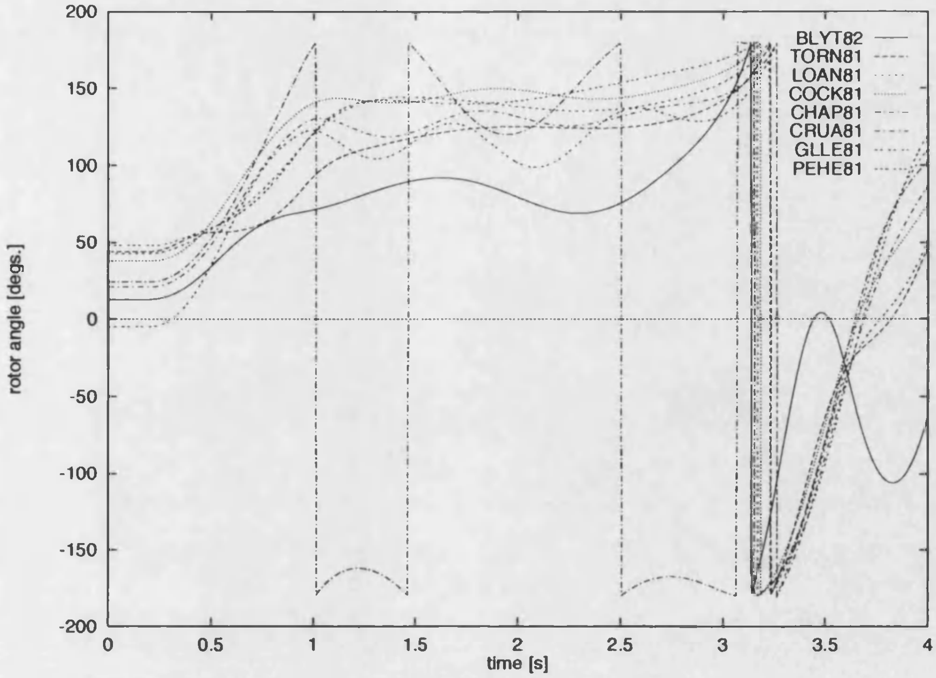


Figure B.3: A rotor angle vs time plot for the Harker-Hutton first swing unstable contingency obtained using PSE.

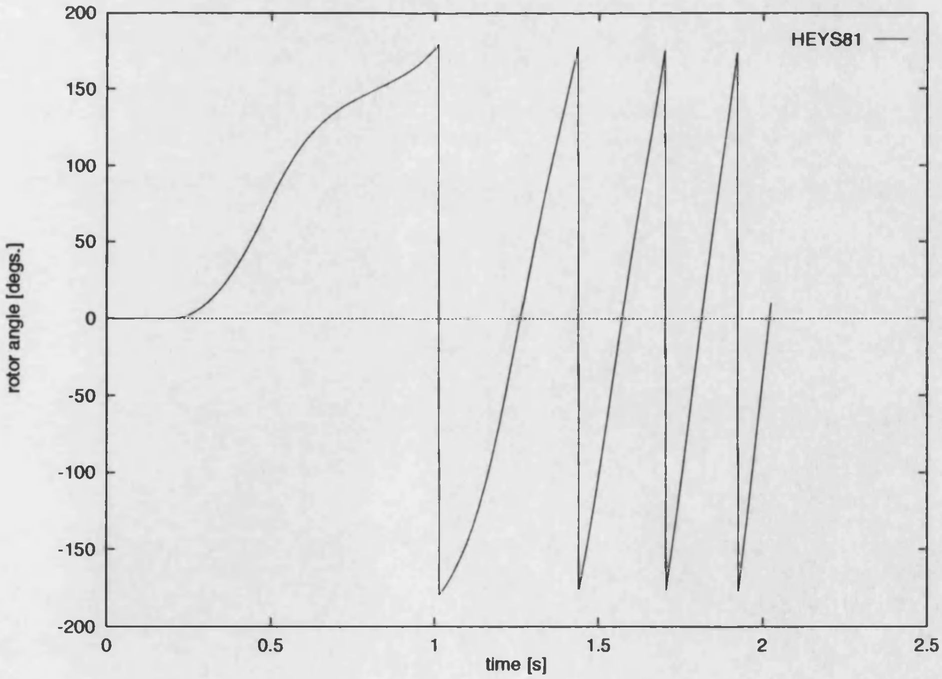


Figure B.4: A rotor angle vs time plot for the Penwortham-Padiham/Kearsley first swing unstable contingency obtained using PSE.

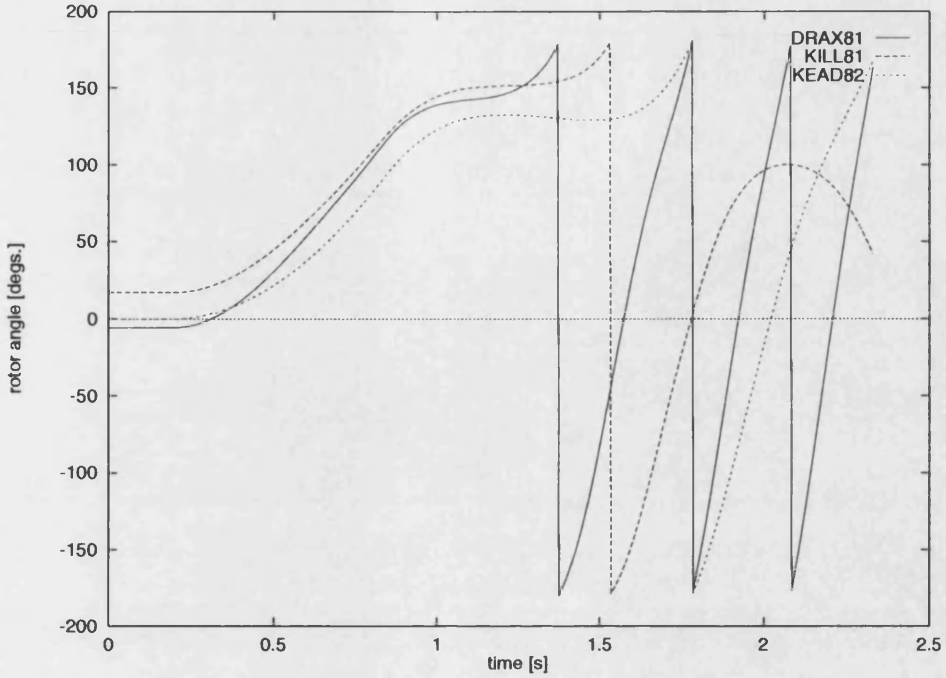


Figure B.5: A rotor angle vs time plot for the Keadby-West Burton first swing unstable contingency obtained using PSE.

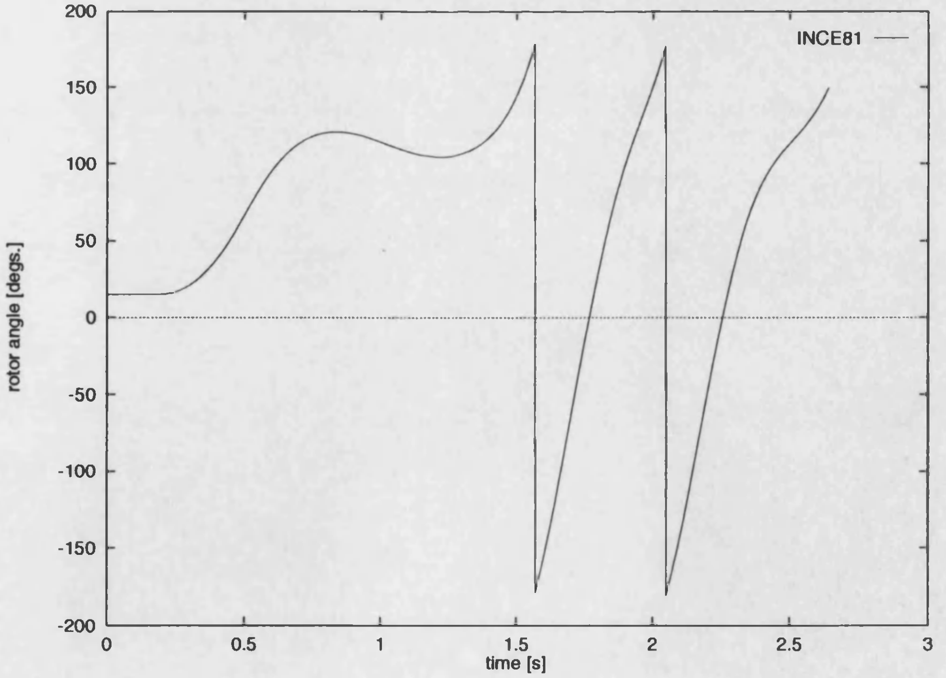


Figure B.6: A rotor angle vs time plot for the Deeside-Trawsfynydd-Legacy first swing unstable contingency obtained using PSE.

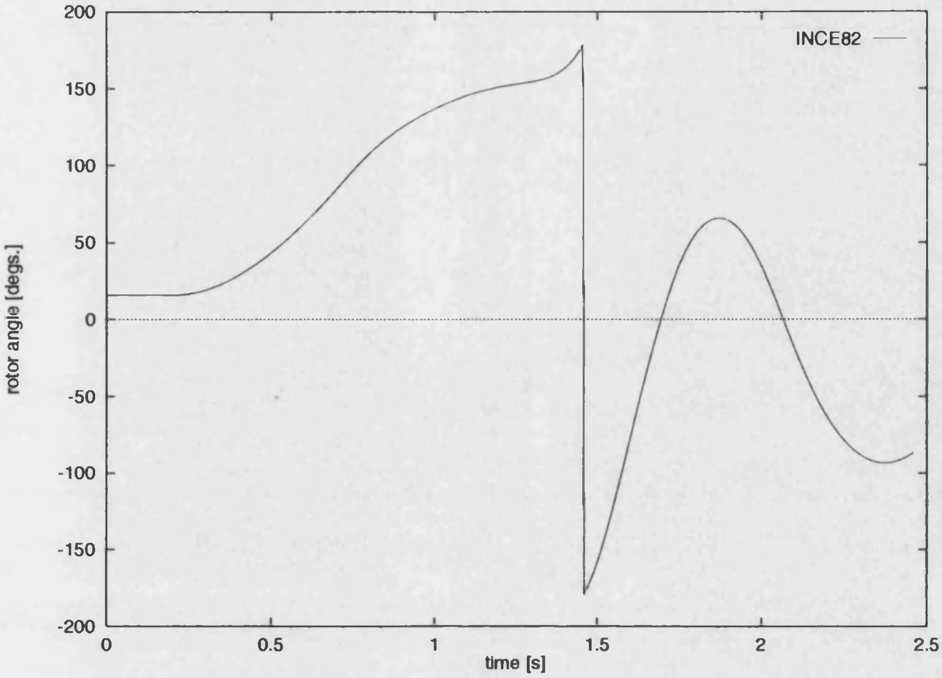


Figure B.7: A rotor angle vs time plot for the Cellerhead-Macclesfield-Daines first swing unstable contingency obtained using PSE.

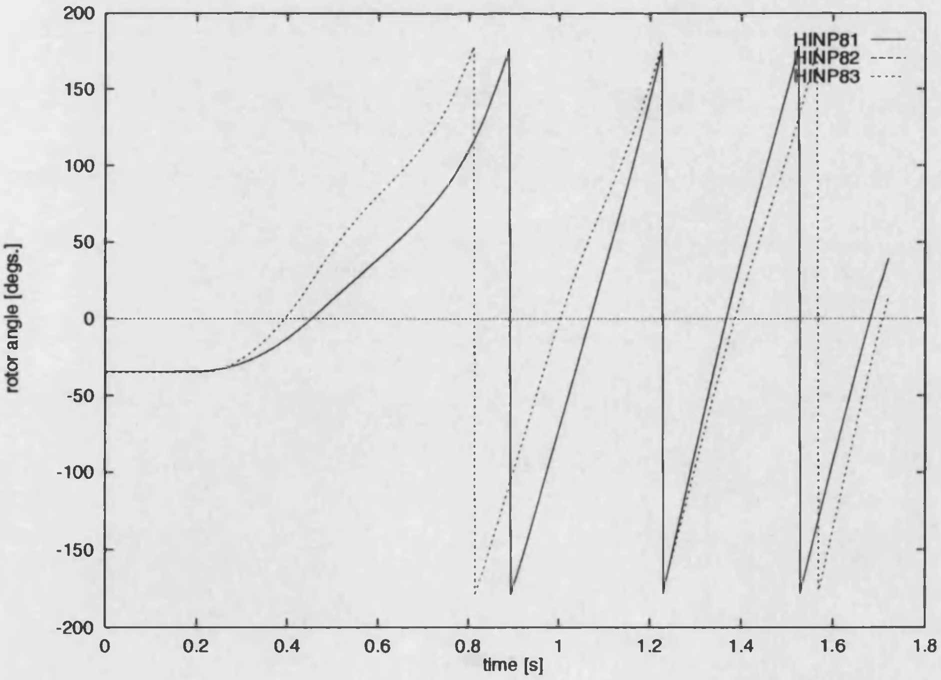


Figure B.8: A rotor angle vs time plot for the Hinkley Point-Melksham first swing unstable contingency obtained using PSE.

Machine group	Constraint analysis rank order	Sensitivity analysis rank order	TEM sensitivity (p.u)	Constraints required to nearest MW
CRUA81	6	1 I	-3.1	-10.8
HUER81	2	2 I	-3.9	-9.1
SLOY81	10	3 I	-2.9	-11.6
CRUA82	7	4 I	-3.1	-10.8
LEVE81	13	5 I	-4.9	-12.2
KIIN81	12	6 I	-4.7	-11.9
ERRO82	11	7 I	-3.6	-11.6
TORN81	18	8 I	-	-12.5
KEOO81	3	9 I	-9.5	-10.0
ERRO81	14	10 I	-3.1	-12.2
LOAN81	8	11 I	-3.0	-11.4
GLLE81	5	12 I	-9.4	-10.7
LOAN82	9	13 I	-2.8	-11.4
TONG81	4	14 I	-16.0	-10.2
SHIN81	19	15 I	-5.9	-12.7
COCK81	22	16 I	-0.7	-13.1
PEHE81	20	17 I	-1.2	-12.9
FASN81	17	18 I	-4.7	-12.4
FAUG81	15	19 I	-2.8	-12.3
CHAP81	1	20 I	-1.3	-3.4
BEAU82	21	21 I	-3.1	-13.0
BEAU81	16	22 I	-2.7	-12.4
BLYT82	0	23 I	-	-
BLYT81	23	24 I	-0.3	-154.2
HATL82	0	25 I	-	-
HATL81	0	26 I	-	-
GRST81	0	27 I	-	-
GRST82	0	28 I	-	-
SALH82	0	29 I	-	-
GRST83	0	30 I	-	-
GRST84	0	31 I	-	-
SALH81	0	32 I	-	-
DRAX81	0	33 I	-	-
KILL81	0	34 I	-	-
SHBA81	0	35 I	-	-
SHBA82	0	36 I	-	-
KILL82	0	37 I	-	-
DRAX82	0	38 D	-	-
COTT81	0	39 D	-	-
KILL83	0	40 D	-	-
KILL85	0	41 D	-	-
EGGB81	0	42 D	-	-
KILL84	0	43 D	-	-
HEYS81	0	44 D	-	-
FERR82	0	45 D	-	-
KEAD81	0	46 D	-	-
KEAD82	0	47 D	-	-
EGGB82	0	48 D	-	-
KEAD83	0	49 D	-	-
FERR81	0	50 D	-	-
KEAD84	0	51 D	-	-
WBUR81	0	52 D	-	-
SUTB81	0	53 D	-	-
SIZE81	0	54 D	-	-
HINP83	0	55 D	-	-
DUNG82	0	56 D	-	-
WYLF81	0	57 D	-	-
FIDF82	0	58 D	-	-
INCE82	0	59 D	-	-
DUNG81	0	60 D	-	-
SUTB82	0	61 D	-	-
INCE81	0	62 D	-	-
RUGE81	0	63 D	-	-
FIDF83	0	64 D	-	-
FIDF81	0	65 D	-	-
DIDC81	0	66 D	-	-
HINP81	0	67 D	-	-
HINP82	0	68 D	-	-
RYEH82	0	69 D	-	-
RATS81	0	70 D	-	-
RYEH81	0	71 D	-	-
BARK83	0	72 D	-	-
IRON81	0	73 D	-	-
DEES81	0	74 D	-	-
EASO81	0	75 D	-	-
KINO81	0	76 D	-	-
MEDW81	0	77 D	-	-
BARK84	0	78 D	-	-
BARK81	0	79 D	-	-
RATS82	0	80 D	-	-
EASO82	0	81 D	-	-
SEAB81	0	82 D	-	-
BARK82	0	83 D	-	-
DEES82	0	84 D	-	-
SEAB82	0	85 D	-	-
MEDW82	0	86 D	-	-
DEES83	0	87 D	-	-

Table B.1: Base case results for Strathaven contingency (transiently unstable)

Machine group	Constraint analysis rank order	Sensitivity analysis rank order	TEM sensitivity (p.u)	Constraints required to nearest MW
TORN81	1	1 I	-1.4	-5.0
HUER81	4	2 I	-4.9	-9.1
COCK81	3	3 I	-2.0	-7.9
LOAN81	8	4 I	-0.4	-9.6
CRUA81	6	5 I	-4.6	-9.3
SLOY81	12	6 I	-4.3	-9.9
ERRO82	11	7 I	-5.4	-9.8
LOAN82	9	8 I	-0.4	-9.6
LEVE81	7	9 I	-7.1	-9.6
CRUA82	5	10 I	-4.5	-9.3
PEHE81	16	11 I	-4.3	-10.3
ERRO81	13	12 I	-4.7	-10.0
KIIN81	10	13 I	-4.6	-9.6
SHIN81	17	14 I	-10.3	-10.4
KEOO81	14	15 I	-15.5	-10.0
BEAU82	21	16 I	-4.6	-10.8
FASN81	15	17 I	-8.3	-10.2
BEAU81	20	18 I	-4.1	-10.7
FAUG81	18	19 I	-4.2	-10.6
GLLE81	19	20 I	-15.4	-10.7
TONG81	22	21 I	-27.0	-10.9
CHAP81	2	22 I	-2.0	-7.6
BLYT81	0	23 I	-	-
BLYT82	0	24 I	-	-
HATL82	0	25 I	-	-
HATL81	0	26 I	-	-
HEYS81	0	27 I	-	-
GRST81	0	28 I	-	-
SALH82	0	29 I	-	-
SALH81	0	30 I	-	-
GRST82	0	31 I	-	-
INCE82	0	32 I	-	-
GRST84	0	33 I	-	-
INCE81	0	34 I	-	-
FIDF82	0	35 I	-	-
GRST83	0	36 I	-	-
FIDF81	0	37 I	-	-
FIDF83	0	38 I	-	-
DRAX82	0	39 D	-	-
FERR82	0	40 D	-	-
FERR81	0	41 D	-	-
WYLF81	0	42 D	-	-
DRAX81	0	43 D	-	-
COTT81	0	44 D	-	-
EGGB81	0	45 D	-	-
KILL81	0	46 D	-	-
DEES81	0	47 D	-	-
RUGE81	0	48 D	-	-
EGGB82	0	49 D	-	-
SHBA81	0	50 D	-	-
SHBA82	0	51 D	-	-
SIZE81	0	52 D	-	-
DEES82	0	53 D	-	-
IRON81	0	54 D	-	-
KILL82	0	55 D	-	-
SUTB81	0	56 D	-	-
KILL85	0	57 D	-	-
WBUR81	0	58 D	-	-
DUNG82	0	59 D	-	-
HINP83	0	60 D	-	-
KILL83	0	61 D	-	-
DIDC81	0	62 D	-	-
KILL84	0	63 D	-	-
DEES83	0	64 D	-	-
KEAD81	0	65 D	-	-
RATS81	0	66 D	-	-
KEAD83	0	67 D	-	-
KEAD82	0	68 D	-	-
BARK83	0	69 D	-	-
BARK81	0	70 D	-	-
SUTB82	0	71 D	-	-
KINO81	0	72 D	-	-
KEAD84	0	73 D	-	-
RYEH81	0	74 D	-	-
DUNG81	0	75 D	-	-
RYEH82	0	76 D	-	-
SEAB81	0	77 D	-	-
RATS82	0	78 D	-	-
BARK84	0	79 D	-	-
MEDW81	0	80 D	-	-
EASO81	0	81 D	-	-
HINP81	0	82 D	-	-
SEAB82	0	83 D	-	-
HINP82	0	84 D	-	-
EASO82	0	85 D	-	-
BARK82	0	86 D	-	-
MEDW82	0	87 D	-	-

Table B.2: Base case results for Eccles contingency (first swing transiently unstable)

Machine group	Constraint analysis rank order	Sensitivity analysis rank order	TEM sensitivity (p.u)	Constraints required to nearest MW
CHAP81	1	1 I	-4.0	-2.5
TONG81	2	2 I	-5.9	-3.1
KEOO81	4	3 I	-3.3	-3.6
HUER81	5	4 I	-0.3	-4.2
GLLE81	3	5 I	-3.3	-3.6
CRUA81	6	6 I	-0.8	-4.6
CRUA82	7	7 I	-0.8	-4.6
SLOY81	8	8 I	-0.7	-5.0
COCK81	0	9 I	-	-
TORN81	9	10 I	-0.3	-5.0
LOAN81	20	11 I	-0.2	-634.2
LOAN82	21	12 I	-0.2	-653.5
KIIN81	11	13 I	-0.8	-5.2
ERRO81	10	14 I	-0.9	-5.0
LEVE81	12	15 I	-1.4	-5.2
ERRO82	13	16 I	-1.0	-5.5
SHIN81	15	17 I	-2.0	-5.8
FAUG81	14	18 I	-0.8	-5.7
FASN81	18	19 I	-1.6	-5.9
PEHE81	0	20 I	-	-
BLYT81	0	21 I	-	-
BEAU82	16	22 I	-0.9	-5.8
BLYT82	19	23 I	-0.6	-10.2
BEAU81	17	24 I	-0.7	-5.8
HATL82	0	25 I	-	-
HATL81	0	26 I	-	-
GRST81	0	27 I	-	-
GRST82	0	28 I	-	-
BARK84	0	29 I	-	-
GRST83	0	30 I	-	-
GRST84	0	31 I	-	-
SALH82	0	32 I	-	-
SEAB82	0	33 I	-	-
SEAB81	0	34 I	-	-
BARK82	0	35 I	-	-
BARK83	0	36 I	-	-
BARK81	0	37 I	-	-
DUNG81	0	38 I	-	-
SALH81	0	39 I	0.1	-
HINP83	0	40 I	-	-
HINP81	0	41 I	-	-
HINP82	0	42 I	-	-
SUTB82	0	43 D	-	-
SIZE81	0	44 D	-	-
SUTB81	0	45 D	-	-
KILL84	0	46 D	0.1	-
KINO81	0	47 D	-	-
DUNG82	0	48 D	-	-
KILL82	0	49 D	0.1	-
KILL85	0	50 D	0.1	-
MEDW81	0	51 D	-	-
DIDC81	0	52 D	-	-
KEAD84	0	53 D	0.1	-
MEDW82	0	54 D	-	-
SHBA81	0	55 D	0.1	-
KEAD83	0	56 D	0.1	-
EASO82	0	57 D	-	-
RYEH82	0	58 D	-	-
COTT81	0	59 D	-	-
RUGE81	0	60 D	-	-
RATS81	0	61 D	-	-
KILL83	0	62 D	0.1	-
EASO81	0	63 D	-	-
KILL81	0	64 D	0.1	-
DRAX81	0	65 D	0.1	-
SHBA82	0	66 D	0.1	-
RATS82	0	67 D	-	-
RYEH81	0	68 D	-	-
KEAD82	0	69 D	0.1	-
IRON81	0	70 D	-	-
DRAX82	0	71 D	0.1	-
KEAD81	0	72 D	0.1	-
WBUR81	0	73 D	-	-
EGGB81	0	74 D	0.1	-
WYLF81	0	75 D	0.1	-
EGGB82	0	76 D	0.1	-
INCE81	0	77 D	0.1	-
FERR82	0	78 D	0.1	-
FERR81	0	79 D	0.1	-
HEYS81	0	80 D	0.2	-
DEES83	0	81 D	0.1	-
DEES81	0	82 D	0.1	-
DEES82	0	83 D	0.1	-
FIDF81	0	84 D	0.1	-
INCE82	0	85 D	0.1	-
FIDF82	0	86 D	0.1	-
FIDF83	0	87 D	0.1	-

Table B.3: Base case results for Harker-Hutton contingency (first swing transiently unstable)

Machine group	Constraint analysis rank order	Sensitivity analysis rank order	TEM sensitivity (p.u)	Constraints required to nearest MW
HEYS81	1	1 I	-5.05	-19.3
FIDF82	0	2 I	0.4	-
FIDF83	0	3 I	0.4	-
FIDF81	0	4 I	0.3	-
INCE82	0	5 I	0.3	-
GLLE81	0	6 I	0.3	-
KEOO81	0	7 I	0.3	-
INCE81	0	8 I	0.2	-
HUER81	0	9 I	0.3	-
TONG81	0	10 I	0.3	-
TORN81	0	11 I	0.3	-
BLYT82	0	12 I	0.2	-
CHAP81	0	13 I	0.3	-
CRUA81	0	14 I	0.3	-
FERR81	0	15 I	0.1	-
CRUA82	0	16 I	0.3	-
BLYT81	0	17 I	0.2	-
SLOY81	0	18 I	0.3	-
FERR82	0	19 I	0.1	-
LOAN81	0	20 I	0.3	-
HATL82	0	21 I	0.2	-
KIIN81	0	22 I	0.3	-
LOAN82	0	23 I	0.3	-
HATL81	0	24 I	0.2	-
ERRO81	0	25 I	0.3	-
ERRO82	0	26 I	0.3	-
GRST82	0	27 I	0.2	-
GRST81	0	28 I	0.2	-
DRAX82	0	29 I	0.1	-
COCK81	0	30 I	0.3	-
EGGB82	0	31 I	0.1	-
LEVE81	0	32 I	0.3	-
SHIN81	0	33 I	0.2	-
GRST83	0	34 I	0.2	-
DEES82	0	35 I	0.2	-
PEHE81	0	36 I	0.3	-
GRST84	0	37 I	0.2	-
FASN81	0	38 I	0.2	-
FAUG81	0	39 I	0.2	-
BEAU82	0	40 I	0.2	-
BEAU81	0	41 I	0.2	-
WYLF81	0	42 I	0.1	-
DEES81	0	43 I	0.2	-
SALH82	0	44 I	0.2	-
SALH81	0	45 I	0.2	-
DEES83	0	46 I	0.2	-
DRAX81	0	47 I	0.1	-
EGGB81	0	48 I	0.1	-
KILL81	0	49 D	0.1	-
IRON81	0	50 D	0.1	-
RUGE81	0	51 D	-	-
WBUR81	0	52 D	0.1	-
COTT81	0	53 D	0.1	-
SHBA82	0	54 D	0.1	-
SHBA81	0	55 D	0.1	-
HINP83	0	56 D	-	-
KILL83	0	57 D	0.1	-
KILL82	0	58 D	0.1	-
KEAD81	0	59 D	0.1	-
KEAD82	0	60 D	0.1	-
SIZE81	0	61 D	-	-
DUNG82	0	62 D	-	-
SUTB81	0	63 D	-	-
KILL85	0	64 D	0.1	-
BARK83	0	65 D	-	-
RATS81	0	66 D	-	-
BARK84	0	67 D	-	-
KILL84	0	68 D	0.1	-
KINO81	0	69 D	-	-
SUTB82	0	70 D	-	-
RATS82	0	71 D	-	-
BARK81	0	72 D	-	-
BARK82	0	73 D	-	-
HINP81	0	74 D	-	-
SEAB82	0	75 D	-	-
KEAD83	0	76 D	0.1	-
SEAB81	0	77 D	-	-
DUNG81	0	78 D	-	-
HINP82	0	79 D	-	-
KEAD84	0	80 D	0.1	-
DIDC81	0	81 D	-	-
MEDW82	0	82 D	-	-
MEDW81	0	83 D	-	-
RYEH81	0	84 D	-	-
EASO81	0	85 D	-	-
EASO82	0	86 D	-	-
RYEH82	0	87 D	-	-

Table B.4: Base case results for Penwortham-Padiham/Kearsley contingency (first swing transiently unstable)

Machine group	Constraint analysis rank order	Sensitivity analysis rank order	TEM sensitivity (p.u)	Constraints required to nearest MW
KILL82	1	1 I	-0.1	-18.7
KILL81	0	2 I	-	-
KILL84	0	3 I	-	-
KEAD82	0	4 I	-	-
DRAX81	0	5 I	0.1	-
SHBA81	0	6 I	-	-
SHBA82	0	7 I	-	-
KEAD81	0	8 I	-	-
KILL85	0	9 I	0.1	-
KILL83	0	10 I	0.1	-
KEAD84	0	11 I	0.1	-
KEAD83	0	12 I	0.1	-
EGGB81	0	13 I	0.1	-
COTT81	0	14 I	0.1	-
WBUR81	0	15 I	0.2	-
GRST83	0	16 I	0.1	-
GRST84	0	17 I	-	-
LOAN82	0	18 I	-	-
LOAN81	0	19 I	-	-
PEHE81	0	20 I	0.1	-
BEAU81	0	21 I	-	-
SHIN81	0	22 I	-	-
BEAU82	0	23 I	-	-
ERRO82	0	24 I	-	-
ERRO81	0	25 I	-	-
FAUG81	0	26 I	-	-
FASN81	0	27 I	-	-
KIIN81	0	28 I	-	-
GRST82	0	29 I	0.1	-
GRST81	0	30 I	0.1	-
GLLE81	0	31 I	-	-
TONG81	0	32 I	-	-
HATL81	0	33 I	0.2	-
HATL82	0	34 I	0.2	-
LEVE81	0	35 I	-	-
BLYT82	0	36 I	-	-
SALH82	0	37 I	0.1	-
DRAX82	0	38 I	0.2	-
SALH81	0	39 I	0.2	-
BLYT81	0	40 I	0.1	-
SLOY81	0	41 D	-	-
CRUA81	0	42 D	-	-
CRUA82	0	43 D	-	-
HUER81	0	44 D	0.1	-
COCK81	0	45 D	-	-
KEOO81	0	46 D	-	-
TORN81	0	47 D	0.2	-
CHAP81	0	48 D	-	-
HINP81	0	49 D	-	-
HINP82	0	50 D	-	-
WYLF81	0	51 D	0.1	-
SEAB82	0	52 D	-	-
SEAB81	0	53 D	-	-
DUNG81	0	54 D	-	-
HINP83	0	55 D	-	-
EGGB82	0	56 D	0.1	-
INCE82	0	57 D	0.1	-
BARK83	0	58 D	-	-
FERR82	0	59 D	0.1	-
INCE81	0	60 D	0.1	-
HEYS81	0	61 D	0.2	-
FIDF82	0	62 D	0.1	-
BARK81	0	63 D	-	-
FERR81	0	64 D	0.1	-
BARK82	0	65 D	-	-
FIDF83	0	66 D	-	-
FIDF81	0	67 D	-	-
BARK84	0	68 D	-	-
DUNG82	0	69 D	-	-
DEES83	0	70 D	-	-
KINO81	0	71 D	-	-
DEES82	0	72 D	0.1	-
RUGE81	0	73 D	-	-
DEES81	0	74 D	0.1	-
DIDC81	0	75 D	-	-
RATS81	0	76 D	-	-
SUTB82	0	77 D	-	-
RATS82	0	78 D	-	-
IRON81	0	79 D	-	-
SUTB81	0	80 D	-	-
MEDW82	0	81 D	-	-
SIZE81	0	82 D	-	-
MEDW81	0	83 D	-	-
RYEH82	0	84 D	-	-
EASO82	0	85 D	-	-
RYEH81	0	86 D	-	-
EASO81	0	87 D	-	-

Table B.5: Base case results for Keadby-West Burton contingency (first swing transiently unstable)

Machine group	Constraint analysis rank order	Sensitivity analysis rank order	TEM sensitivity (p.u)	Constraints required to nearest MW
DEES82	0	1 I	-	-
INCE81	1	2 I	-2.7	-1.0
FIDF81	2	3 I	-0.1	-23.4
DEES83	0	4 I	-	-
FIDF82	0	5 I	-	-
INCE82	3	6 I	-0.1	-381.0
FIDF83	0	7 I	-	-
WYLF81	0	8 I	-	-
DEES81	0	9 I	-	-
HEYS81	0	10 I	-	-
FERR81	0	11 I	-	-
FERR82	0	12 I	-	-
GLLE81	0	13 I	-	-
DRAX82	0	14 I	-	-
EGGB82	0	15 I	-	-
KEOO81	0	16 I	-	-
LOAN81	0	17 I	-	-
LOAN82	0	18 I	-	-
TONG81	0	19 I	-	-
IRON81	0	20 I	-	-
CHAP81	0	21 I	-	-
HATL81	0	22 I	-	-
PEHE81	0	23 I	-	-
ERRO81	0	24 I	-	-
SLOY81	0	25 I	-	-
HUER81	0	26 I	-	-
BLYT82	0	27 I	-	-
TORN81	0	28 I	-	-
KIIN81	0	29 I	-	-
BEAU81	0	30 I	-	-
BLYT81	0	31 I	-	-
ERRO82	0	32 I	-	-
BEAU82	0	33 I	-	-
RUGE81	0	34 I	-	-
FAUG81	0	35 I	-	-
COCK81	0	36 I	-	-
SHIN81	0	37 I	-	-
CRUA81	0	38 I	-	-
EGGB81	0	39 I	-	-
DRAX81	0	40 I	-	-
CRUA82	0	41 I	-	-
FASN81	0	42 I	-	-
HATL82	0	43 D	-	-
GRST82	0	44 D	-	-
GRST81	0	45 D	-	-
GRST83	0	46 D	-	-
GRST84	0	47 D	-	-
SALH82	0	48 D	-	-
LEVE81	0	49 D	-	-
SALH81	0	50 D	-	-
KILL81	0	51 D	-	-
RATS82	0	52 D	-	-
RATS81	0	53 D	-	-
WBUR81	0	54 D	-	-
COTT81	0	55 D	-	-
SIZE81	0	56 D	-	-
DUNG82	0	57 D	-	-
SHBA82	0	58 D	-	-
SHBA81	0	59 D	-	-
KILL82	0	60 D	-	-
HINP83	0	61 D	-	-
KILL84	0	62 D	-	-
KILL85	0	63 D	-	-
SUTB81	0	64 D	-	-
KINO81	0	65 D	-	-
KILL83	0	66 D	-	-
KEAD81	0	67 D	-	-
KEAD82	0	68 D	-	-
SUTB82	0	69 D	-	-
BARK83	0	70 D	-	-
DUNG81	0	71 D	-	-
HINP81	0	72 D	-	-
BARK81	0	73 D	-	-
HINP82	0	74 D	-	-
KEAD83	0	75 D	-	-
KEAD84	0	76 D	-	-
BARK82	0	77 D	-	-
DIDC81	0	78 D	-	-
BARK84	0	79 D	-	-
SEAB81	0	80 D	-	-
SEAB82	0	81 D	-	-
MEDW81	0	82 D	-	-
MEDW82	0	83 D	-	-
RYEH81	0	84 D	-	-
EASO81	0	85 D	-	-
RYEH82	0	86 D	-	-
EASO82	0	87 D	-	-

Table B.6: Base case results for Deeside-Trawsfynydd-Legacy contingency (first swing transiently unstable)

Machine group	Constraint analysis rank order	Sensitivity analysis rank order	TEM sensitivity (p.u)	Constraints required to nearest MW
FIDF81	1	1 I	-6.1	-4.9
FIDF82	2	2 I	-6.3	-4.9
FIDF83	3	3 I	-6.3	-4.9
INCE82	4	4 I	-5.5	-8.8
HEYS81	5	5 I	-	-9.7
INCE81	6	6 I	-0.5	-39.0
DEES82	7	7 I	-0.8	-41.0
DEES83	0	8 I	-	-
WYLF81	0	9 I	0.1	-
DEES81	0	10 I	0.5	-
IRON81	0	11 I	0.2	-
TONG81	0	12 I	0.1	-
HINP81	0	13 I	-	-
GLLE81	0	14 I	0.1	-
HINP82	0	15 I	-	-
BLYT82	0	16 I	-0.1	-
ERRO82	0	17 I	-0.1	-
BEAU81	0	18 I	-0.1	-
BEAU82	0	19 I	-0.1	-
KEOO81	0	20 I	0.1	-
SLOY81	0	21 I	-0.1	-
FAUG81	0	22 I	-0.1	-
ERRO81	0	23 I	-0.1	-
FERR81	0	24 D	0.1	-
FERR82	0	25 D	0.1	-
LOAN82	0	26 D	0.1	-
LOAN81	0	27 D	0.1	-
PEHE81	0	28 D	0.2	-
SHIN81	0	29 D	0.1	-
DUNG81	0	30 D	-	-
KIIN81	0	31 D	-0.1	-
BARK83	0	32 D	-	-
HINP83	0	33 D	-	-
RUGE81	0	34 D	0.1	-
SEAB82	0	35 D	-	-
SEAB81	0	36 D	-	-
BARK81	0	37 D	-	-
SIZE81	0	38 D	-	-
FASN81	0	39 D	0.1	-
KINO81	0	40 D	-	-
DUNG82	0	41 D	-	-
HUER81	0	42 D	0.2	-
BARK82	0	43 D	-	-
SUTB81	0	44 D	-	-
SUTB82	0	45 D	-	-
BLYT81	0	46 D	0.1	-
TORN81	0	47 D	0.2	-
DRAX82	0	48 D	0.1	-
BARK84	0	49 D	-	-
DIDC81	0	50 D	-	-
CRUA81	0	51 D	-0.1	-
CHAP81	0	52 D	-	-
CRUA82	0	53 D	-0.1	-
GRST81	0	54 D	0.1	-
EGGB82	0	55 D	0.1	-
GRST82	0	56 D	-	-
LEVE81	0	57 D	0.1	-
RATS82	0	58 D	-	-
HATL82	0	59 D	0.1	-
COCK81	0	60 D	0.1	-
RATS81	0	61 D	0.1	-
MEDW81	0	62 D	-	-
GRST83	0	63 D	0.1	-
KILL83	0	64 D	0.1	-
MEDW82	0	65 D	0.1	-
HATL81	0	66 D	0.1	-
GRST84	0	67 D	-	-
RYEH82	0	68 D	-	-
RYEH81	0	69 D	-	-
SHBA82	0	70 D	0.1	-
KILL81	0	71 D	0.1	-
KILL84	0	72 D	-	-
EASO82	0	73 D	-	-
SALH82	0	74 D	0.1	-
COTT81	0	75 D	0.1	-
EASO81	0	76 D	-	-
KEAD84	0	77 D	-	-
KILL82	0	78 D	-	-
SHBA81	0	79 D	0.2	-
WBUR81	0	80 D	0.1	-
KILL85	0	81 D	0.1	-
KEAD83	0	82 D	-	-
SALH81	0	83 D	0.2	-
KEAD82	0	84 D	-	-
KEAD81	0	85 D	-	-
DRAX81	0	86 D	0.1	-
EGGB81	0	87 D	0.1	-

Table B.7: Base case results for Cellerhead-Macclesfield-Daines contingency (first swing transiently unstable)

Machine group	Constraint analysis rank order	Sensitivity analysis rank order	TEM sensitivity (p.u)	Constraints required to nearest MW
HINP83	1	1 I	-0.1	-14.3
HINP81	0	2 I	-	-
HINP82	0	3 I	-	-
DIDC81	0	4 I	-	-
SEAB82	0	5 I	-	-
SEAB81	0	6 I	-	-
DUNG82	0	7 I	0.2	-
KINO81	0	8 I	-	-
DUNG81	0	9 I	0.1	-
MEDW81	0	10 I	0.1	-
SIZE81	0	11 I	-	-
MEDW82	0	12 I	-	-
ERRO81	0	13 I	-	-
PEHE81	0	14 I	-	-
BEAU81	0	15 I	-	-
BEAU82	0	16 I	-	-
FAUG81	0	17 I	-	-
SHIN81	0	18 I	-	-
ERRO82	0	19 I	-	-
KIIN81	0	20 I	-	-
COTT81	0	21 I	-	-
LOAN81	0	22 I	-	-
TONG81	0	23 I	-	-
LOAN82	0	24 I	-	-
HATL81	0	25 I	-	-
COCK81	0	26 I	-	-
GLLE81	0	27 I	-	-
GRST83	0	28 I	-	-
GRST81	0	29 I	-	-
RUGE81	0	30 I	-	-
IRON81	0	31 I	-	-
HUER81	0	32 I	-	-
BLYT81	0	33 I	-	-
HATL82	0	34 I	-	-
DRAX81	0	35 I	-	-
HEYS81	0	36 I	-	-
FASN81	0	37 I	-	-
CRUA82	0	38 I	-	-
GRST82	0	39 I	-	-
CRUA81	0	40 I	-	-
SLOY81	0	41 I	-	-
GRST84	0	42 I	-	-
TORN81	0	43 I	-	-
RATS82	0	44 I	-	-
DRAX82	0	45 I	-	-
CHAP81	0	46 I	-	-
WBUR81	0	47 I	-	-
SUTB81	0	48 I	-	-
LEVE81	0	49 I	-	-
SALH81	0	50 I	-	-
SALH82	0	51 I	-	-
BLYT82	0	52 I	-	-
SUTB82	0	53 I	-	-
EGGB81	0	54 I	-	-
FERR81	0	55 I	-	-
FERR82	0	56 I	-	-
FIDF82	0	57 I	-	-
KILL82	0	58 I	-	-
INCE81	0	59 I	-	-
EGGB82	0	60 I	-	-
FIDF83	0	61 I	-	-
INCE82	0	62 I	-	-
FIDF81	0	63 I	-	-
KILL84	0	64 I	-	-
KEOO81	0	65 I	-	-
WYLF81	0	66 I	-	-
BARK81	0	67 D	-	-
BARK83	0	68 D	-	-
RYEH81	0	69 D	-	-
RATS81	0	70 D	-	-
BARK82	0	71 D	-	-
RYEH82	0	72 D	-	-
KILL81	0	73 D	-	-
KILL85	0	74 D	-	-
SHBA82	0	75 D	-	-
SHBA81	0	76 D	-	-
EASO81	0	77 D	-	-
KILL83	0	78 D	-	-
EASO82	0	79 D	-	-
DEES81	0	80 D	-	-
KEAD82	0	81 D	-	-
KEAD81	0	82 D	-	-
KEAD83	0	83 D	-	-
DEES82	0	84 D	-	-
KEAD84	0	85 D	-	-
BARK84	0	86 D	-	-
DEES83	0	87 D	-	-

Table B.8: Base case results for Hinkley Point-Melksham contingency (first swing transiently unstable)

Appendix C

Composite index selection for subsequent swing instability

The rotor angle plots in figures C.1- C.4 show the generation groups participating in the system mode of disturbance for the four contingencies given in figures A.5- A.8. In some cases, not all the groups participating have been plotted. This has been done to keep the plots uncluttered. The groups that are not shown have trajectories very similar to other groups which have actually been plotted.

All the plots were obtained using PSE, and the fault clearing times shown in figures A.5- A.8. The plots correspond to the set of subsequent swing unstable contingencies used during composite index selection, yielding the results in tables C.1- C.4

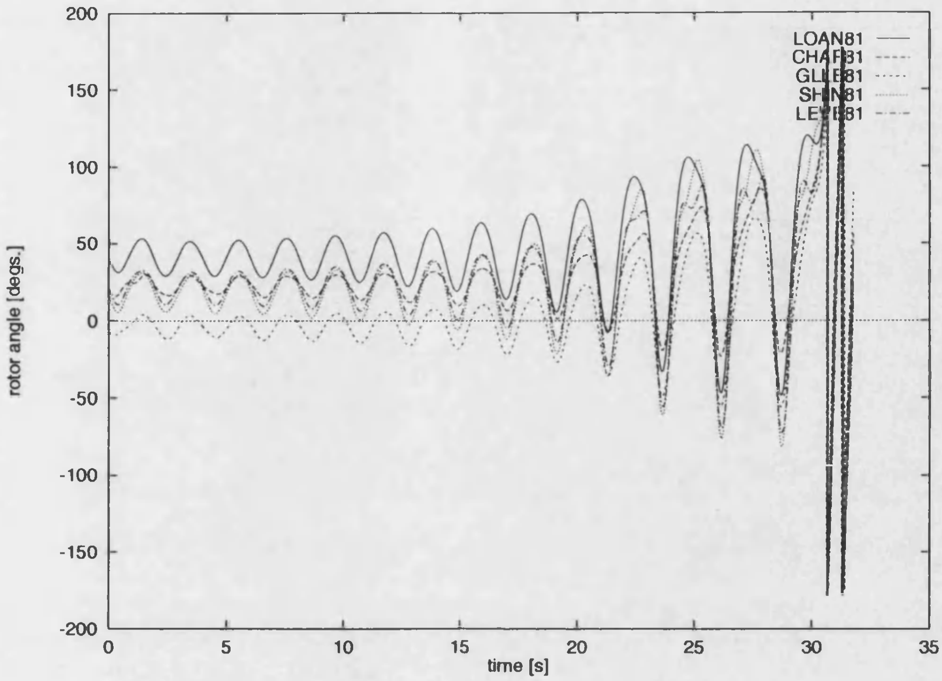


Figure C.1: A rotor angle vs time plot for the Keadby-West Burton subsequent swing unstable contingency obtained using PSE.

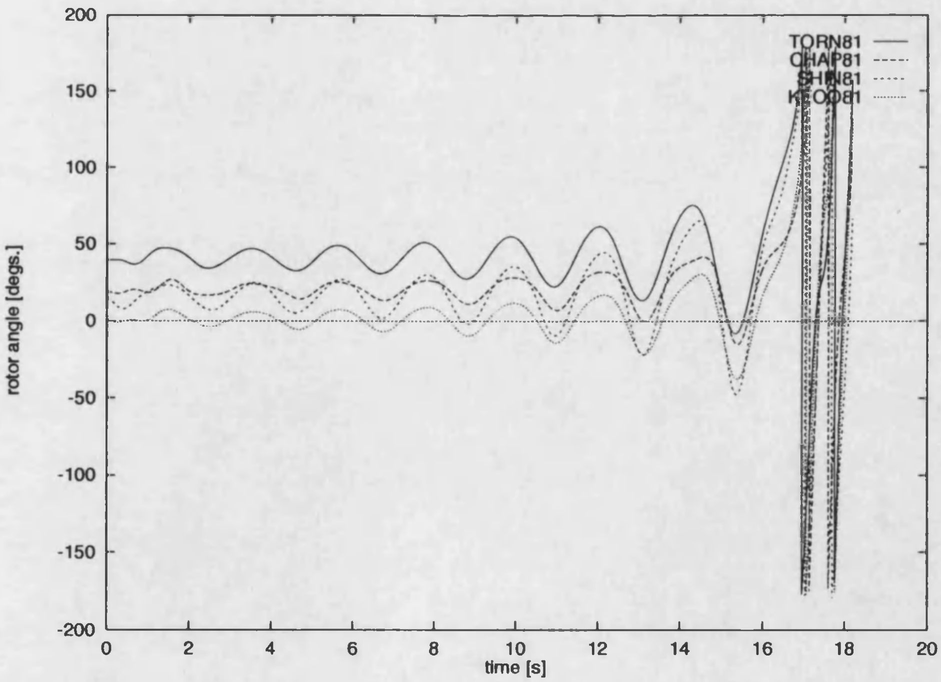


Figure C.2: A rotor angle vs time plot for the Deeside-Trawsfynydd-Legacy subsequent swing unstable contingency obtained using PSE.

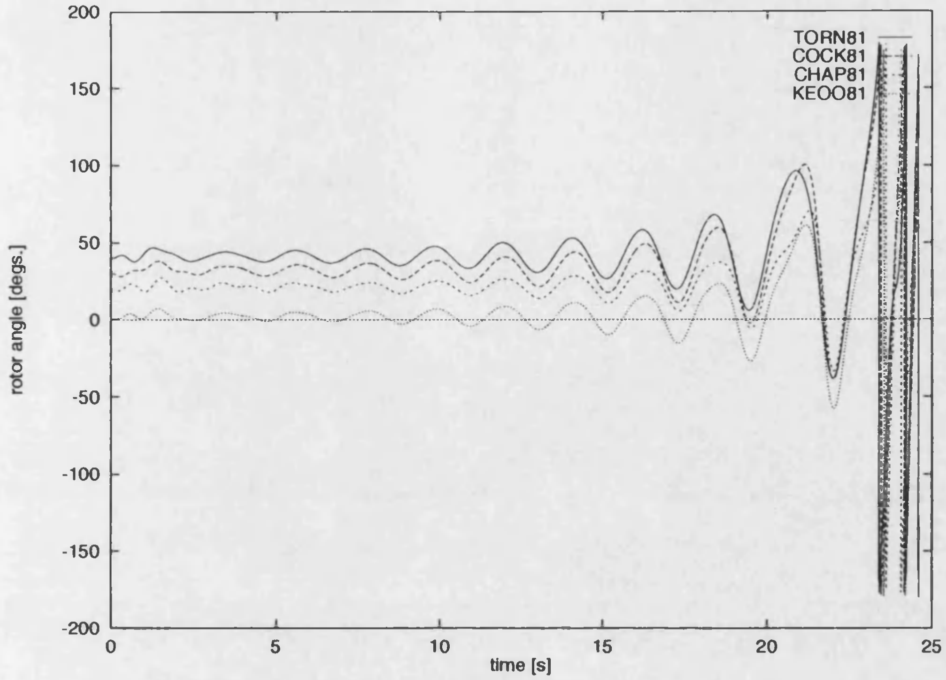


Figure C.3: A rotor angle vs time plot for the Cellerhead-Macclesfield-Daines subsequent swing unstable contingency obtained using PSE.

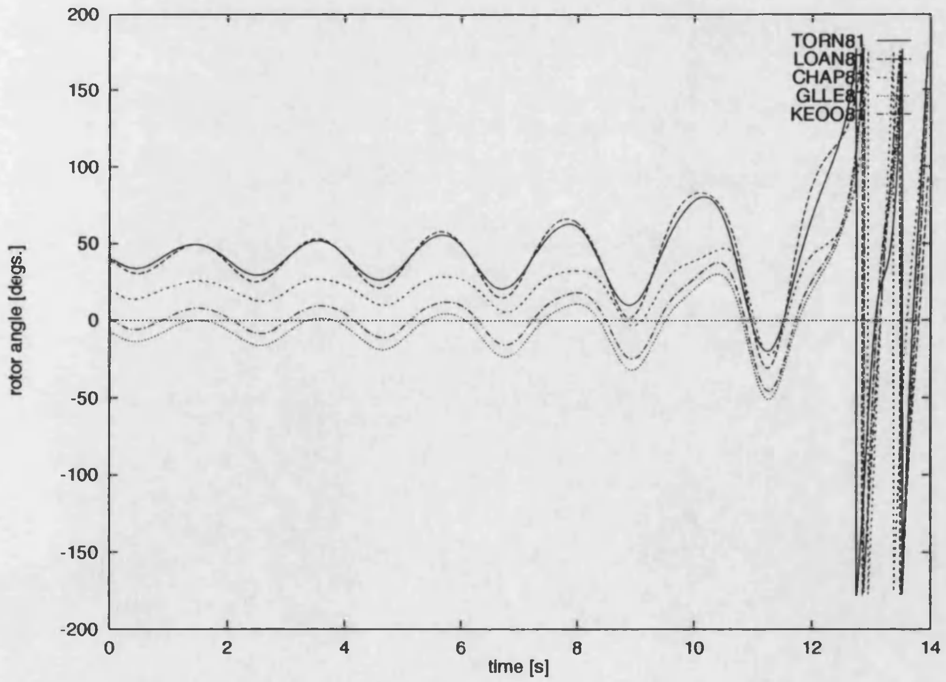


Figure C.4: A rotor angle vs time plot for the Hinkley Point-Melksham subsequent swing unstable contingency obtained using PSE.

Machine group	Constraint analysis rank order	Sensitivity analysis rank order	Constraints required to nearest MW
PEHE81	1	1 I	-26.3
BEAU82	3	2 I	-34.1
BEAU81	5	3 I	-34.4
SHIN81	0	4 I	-
FASN81	6	5 I	-34.8
ERRO82	7	6 I	-35.3
LEVE81	9	7 I	-39.2
FAUG81	8	8 I	-35.8
ERRO81	10	9 I	-41.5
LOAN81	4	10 I	-34.4
LOAN82	2	11 I	-33.8
KIIN81	11	12 I	-45.2
CRUA81	14	13 I	-48.4
SLOY81	12	14 I	-46.5
CRUA82	13	15 I	-47.9
HUER81	15	16 I	-52.6
COCK81	16	17 I	-54.9
TORN81	17	18 I	-60.7
CHAP81	18	19 I	-125.0
GLLE81	0	20 I	-
KEOO81	0	21 I	-
TONG81	0	22 I	-
DUNG81	0	23 I	-
SUTB82	22	24 I	-424.9
DUNG82	0	25 I	-
HEYS81	0	26 I	-
SIZE81	19	27 I	-318.3
SUTB81	0	28 I	-
MEDW81	23	29 I	-430.7
INCE82	0	30 I	-
BARK84	0	31 I	-
WYLF81	0	32 I	-
DEES81	0	33 I	-
INCE81	0	34 I	-
BARK82	0	35 I	-
HINP81	0	36 I	-
HINP82	0	37 I	-
MEDW82	0	38 I	-
RYEH82	0	39 I	-
BARK81	0	40 I	-
RATS81	24	41 I	-492.0
SALH82	26	42 I	-1051.9
RYEH81	0	43 I	-
SEAB82	0	44 I	-
BARK83	0	45 I	-
HINP83	20	46 I	-351.2
DEES83	0	47 I	-
SEAB81	21	48 I	-358.2
RATS82	25	49 I	-755.6
DEES82	0	50 I	-
EASO82	0	51 I	-
EASO81	0	52 I	-
FERR81	0	53 I	-
EGGB82	0	54 I	-
FERR82	0	55 I	-
COTT81	0	56 I	-
HATL82	0	57 M	-
HATL81	0	58 M	-
SALH81	0	59 D	-
KILL84	0	60 D	-
DRAX82	0	61 D	-
EGGB81	0	62 D	-
KEAD81	0	63 D	-
KEAD83	0	64 D	-
KEAD84	0	65 D	-
KEAD82	0	66 D	-
KILL85	0	67 D	-
KILL83	0	68 D	-
KILL81	0	69 D	-
KILL82	0	70 D	-
SHBA81	0	71 D	-
SHBA82	0	72 D	-

Table C.1: Base case results for Keadby-West Burton contingency (subsequent swing transiently unstable)

Machine group	Constraint analysis rank order	Sensitivity analysis rank order	Constraints required to nearest MW
LOAN82	2	1 I	-117.6
LOAN81	3	2 I	-119.3
PEHE81	1	3 I	-88.7
HUER81	5	4 I	-196.7
TORN81	6	5 I	-238.6
COCK81	4	6 I	-196.3
CRUA81	0	7 I	-
ERRO82	0	8 I	-
CRUA82	0	9 I	-
SLOY81	0	10 I	-
ERRO81	0	11 I	-
CHAP81	0	12 I	-
SHIN81	0	13 I	-
LEVE81	0	14 I	-
BEAU82	0	15 I	-
BEAU81	0	16 I	-
KIIN81	0	17 I	-
FAUG81	0	18 I	-
FASN81	0	19 I	-
GLLE81	0	20 I	-
SALH82	0	21 I	-
KEOO81	0	22 I	-
TONG81	0	23 I	-
SALH81	0	24 I	-
HATL82	0	25 I	-
HATL81	0	26 I	-
KILL84	0	27 I	-
KILL83	0	28 I	-
COTT81	0	29 I	-
EGGB81	0	30 I	-
EGGB82	0	31 I	-
FERR81	0	32 I	-
FERR82	0	33 I	-
KEAD83	0	34 M	-
KILL85	0	35 M	-
KEAD84	0	36 M	-
HEYS81	0	37 M	-
KILL81	0	38 M	-
KILL82	0	39 M	-
SHBA81	0	40 M	-
SHBA82	0	41 M	-
KEAD82	0	42 M	-
KEAD81	0	43 M	-
WYLF81	0	44 M	-
INCE82	0	45 D	-
SUTB82	0	46 D	-
INCE81	0	47 D	-
SUTB81	0	48 D	-
EASO82	0	49 D	-
DUNG81	0	50 D	-
DUNG82	0	51 D	-
EASO81	0	52 D	-
SIZE81	0	53 D	-
DRAX82	0	54 D	-
RYEH82	0	55 D	-
RYEH81	0	56 D	-
MEDW81	0	57 D	-
MEDW82	0	58 D	-
BARK84	0	59 D	-
BARK83	0	60 D	-
BARK82	0	61 D	-
DEES81	0	62 D	-
BARK81	0	63 D	-
RATS81	0	64 D	-
RATS82	0	65 D	-
HINP81	0	66 D	-
HINP82	0	67 D	-
HINP83	0	68 D	-
SEAB82	0	69 D	-
DEES82	0	70 D	-
SEAB81	0	71 D	-
DEES83	0	72 D	-

Table C.2: Base case results for Deeside-Trawsfynydd-Legacy contingency (subsequent swing transiently unstable)

Machine group	Constraint analysis rank order	Sensitivity analysis rank order	Constraints required to nearest MW
PEHE81	1	1 I	-46.4
SHIN81	0	2 I	-
BEAU82	5	3 I	-58.5
BEAU81	2	4 I	-54.9
LOAN82	3	5 I	-55.6
LOAN81	4	6 I	-56.4
FASN81	0	7 I	-
ERRO82	7	8 I	-70.0
LEVE81	0	9 I	-
FAUG81	6	10 I	-64.1
ERRO81	8	11 I	-76.4
KIIN81	0	12 I	-
SLOY81	9	13 I	-95.8
TORN81	13	14 I	-144.9
COCK81	11	15 I	-105.0
HUER81	12	16 I	-108.4
CRUA82	10	17 I	-97.3
KEOO81	0	18 I	-
GLLE81	0	19 I	-
TONG81	0	20 I	-
CRUA81	0	21 I	-
SALH82	0	22 I	-
CHAP81	0	23 I	-
HATL82	0	24 I	-
SALH81	0	25 I	-
KILL84	0	26 I	-
KILL85	0	27 I	-
KILL83	0	28 I	-
KILL81	0	29 I	-
HATL81	0	30 I	-
KEAD84	0	31 I	-
KEAD83	0	32 I	-
KILL82	0	33 I	-
SHBA82	0	34 I	-
SHBA81	0	35 I	-
COTT81	0	36 I	-
KEAD82	0	37 I	-
KEAD81	0	38 I	-
SUTB82	0	39 I	-
SUTB81	0	40 I	-
DUNG81	0	41 I	-
EASO82	0	42 I	-
DUNG82	0	43 I	-
EASO81	0	44 I	-
SIZE81	0	45 I	-
RYEH81	0	46 I	-
RYEH82	0	47 I	-
MEDW81	0	48 I	-
BARK84	0	49 I	-
BARK82	0	50 I	-
MEDW82	0	51 I	-
BARK83	0	52 I	-
BARK81	0	53 I	-
HEYS81	0	54 I	-
HINP81	0	55 I	-
HINP82	0	56 I	-
EGGB81	0	57 I	-
RATS81	0	58 I	-
HINP83	0	59 I	-
RATS82	0	60 I	-
SEAB82	0	61 I	-
SEAB81	0	62 I	-
EGGB82	0	63 I	-
FERR81	0	64 M	-
DRAX82	0	65 D	-
FERR82	0	66 D	-
INCE82	0	67 D	-
INCE81	0	68 D	-
DEES81	0	69 D	-
WYLF81	0	70 D	-
DEES83	0	71 D	-
DEES82	0	72 D	-

Table C.3: Base case results for Cellerhead-Macclesfield-Daines contingency (subsequent swing transiently unstable)

Machine group	Constraint analysis rank order	Sensitivity analysis rank order	Constraints required to nearest MW
LOAN82	2	1 I	-239.3
LOAN81	3	2 I	-240.2
PEHE81	1	3 I	-183.6
LEVE81	0	4 I	-
COCK81	4	5 I	-408.8
ERRO82	0	6 I	-
SLOY81	0	7 I	-
HUER81	5	8 I	-419.9
SHIN81	0	9 I	-
ERRO81	0	10 I	-
KIIN81	0	11 I	-
BEAU82	0	12 I	-
FASN81	0	13 I	-
CRUA82	0	14 I	-
BEAU81	0	15 I	-
FAUG81	0	16 I	-
CRUA81	0	17 I	-
TORN81	6	18 I	-458.4
KEOO81	0	19 I	-
GLLE81	0	20 I	-
TONG81	0	21 I	-
SALH82	0	22 I	-
CHAP81	0	23 I	-
SALH81	0	24 I	-
HATL82	0	25 I	-
HATL81	0	26 I	-
HEYS81	0	27 I	-
KILL85	0	28 I	-
EGGB82	0	29 I	-
KILL84	0	30 I	-
KILL83	0	31 I	-
INCE81	0	32 M	-
FERR81	0	33 M	-
WYLF81	0	34 M	-
INCE82	0	35 D	-
EGGB81	0	36 D	-
KILL81	0	37 D	-
COTT81	0	38 D	-
SHBA81	0	39 D	-
DRAX82	0	40 D	-
KILL82	0	41 D	-
SHBA82	0	42 D	-
RYEH82	0	43 D	-
RYEH81	0	44 D	-
HINP81	0	45 D	-
HINP82	0	46 D	-
KEAD84	0	47 D	-
DEES81	0	48 D	-
FERR82	0	49 D	-
SUTB82	0	50 D	-
DUNG81	0	51 D	-
KEAD83	0	52 D	-
KEAD81	0	53 D	-
HINP83	0	54 D	-
SIZE81	0	55 D	-
BARK84	0	56 D	-
BARK83	0	57 D	-
RATS81	0	58 D	-
BARK81	0	59 D	-
RATS82	0	60 D	-
SUTB81	0	61 D	-
BARK82	0	62 D	-
DUNG82	0	63 D	-
SEAB82	0	64 D	-
MEDW81	0	65 D	-
SEAB81	0	66 D	-
KEAD82	0	67 D	-
MEDW82	0	68 D	-
DEES83	0	69 D	-
DEES82	0	70 D	-
EASO81	0	71 D	-
EASO82	0	72 D	-

Table C.4: Base case results for Hinkley Point-Melksham contingency (subsequent swing transiently unstable)

Appendix D

Data for the CAMEL results

% of time for which demand is greater than:	0	10	20	30	40	50	60	70	80	90	100
Whole year	100.0	85.0	79.0	74.0	72.0	70.0	66.0	62.0	56.0	49.0	40.0
Dec/Jan/Feb	100.0	95.0	93.0	91.3	90.7	90.0	88.7	87.3	85.3	83.0	80.0
Mar/Nov	86.7	81.7	79.7	78.0	77.3	76.7	75.3	74.0	72.0	69.7	66.7
Apr/Sep/Oct	74.3	69.3	67.3	65.7	65.0	64.3	63.0	61.7	59.7	57.3	54.3
May/Jun/Jul/Aug	60.0	55.0	53.0	51.3	50.7	50.0	48.7	47.3	45.3	43.0	40.0

Table D.1: Load duration curve data derived from 1996 NGC Seven Year Statement. Load duration curve for the whole year has been broken down into four seasonal curves for use by CAMEL.

Plant category	Overall availability including planned and forced outages			
	DEC JAN FEB	MAR NOV	APR SEP OCT	MAY JUN JUL AUG
All CCGTs	90%	90%	86%	86%
Large coal:				
National Power	91%	91%	86%	78%
PowerGen	91%	91%	88%	77%
SHE	91%	91%	87%	78%
Medium coal:				
National Power	89%	88%	86%	78%
PowerGen	92%	92%	86%	86%
SP	90%	89%	86%	82%
Small coal:				
National Power	93%	94%	92%	91%
SP	93%	94%	92%	91%
Oil:				
National Power	88%	87%	85%	77%
PowerGen	88%	88%	87%	81%
Nuclear:				
Nuclear Electric	84%	83%	85%	82%
SP	84%	83%	85%	82%
SP	84%	83%	85%	82%
OCGTs:				
National Power	91%	90%	89%	89%
PowerGen	97%	96%	88%	93%
Overall	92%	92%	88%	90%
Hydro:				
SP	93%	94%	92%	91%
SHE	93%	94%	92%	91%

Table D.2: Table of generation plant availability categorised by period of the year and plant type. Note that SP = Scottish Power and SHE = Scottish Hydro Electric.

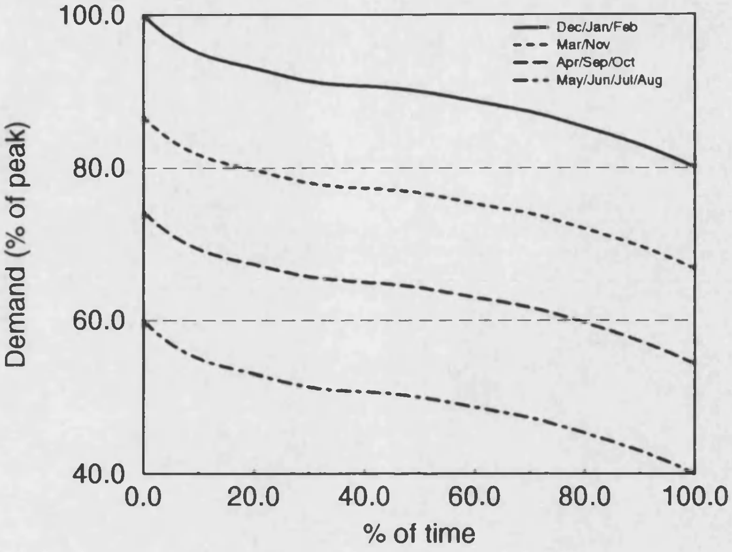


Figure D.1: Load duration curves for the four periods making up one year as used by CAMEL.

Table D.3: Generation offer prices and fuel types as used in all studies. Note that the data in this table is based on tables 3.9, 7.1 and D2.3(a) of the NGC 1996 Seven Year Statement.

Station busbar code	Maximum number of units	Pool offer price £/MWhr	Owner	Plant type
HEYS81	4	0.35	Nuclear Electric	Nuclear
HINP81	3	0.06	Nuclear Electric	Nuclear
HINP82	3	0.06	Nuclear Electric	Nuclear
HINP83	2	0.03	Nuclear Electric	Nuclear
WYLF81	4	0.05	Nuclear Electric	Nuclear
HATL81	1	0.29	Nuclear Electric	Nuclear
HATL82	1	0.29	Nuclear Electric	Nuclear
DUNG81	4	0.02	Nuclear Electric	Nuclear
DUNG82	2	0.00	Nuclear Electric	Nuclear
SIZE81	2	0.00	Nuclear Electric	Nuclear
GRST81	4	17.5	Teeside Power	CCGT
GRST82	1	17.5	Teeside Power	CCGT
GRST83	4	17.5	Teeside Power	CCGT
GRST84	1	17.5	Teeside Power	CCGT
SALH81	4	1.0	Teeside Power	CCGT
SALH82	4	1.0	Teeside Power	CCGT
RUGE81	2	21.15	National Power	Large coal
DRAX81	3	8.36	National Power	Large coal
DRAX82	3	8.36	National Power	Large coal
EGGB81	2	8.28	National Power	Large coal
EGGB82	2	8.28	National Power	Large coal

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Station busbar code	Maximum number of units	Pool offer price £/MWhr	Owner	Plant type
DIDC81	4	29.63	National Power	Large coal
IRON81	2	25.80	National Power	Large coal
FERR81	2	5.76	PowerGen	Large coal
FERR82	2	5.76	PowerGen	Large coal
COTT81	4	4.96	PowerGen	Large coal
SHBA81	6	3.72	Humber Power	CCGT
SHBA82	3	3.72	Humber Power	CCGT
KILL81	4	3.39	PowerGen	CCGT
KILL82	2	3.39	PowerGen	CCGT
KILL83	3	7.73	National Power	CCGT
KILL84	1	7.73	National Power	CCGT
KILL85	2	3.72	PowerGen	CCGT
KEAD81	2	0.00	Keadby Generation	CCGT
KEAD82	1	0.00	Keadby Generation	CCGT
KEAD83	2	3.72	Keadby Development	CCGT
KEAD84	1	3.72	Keadby Development	CCGT
BARK81	2	0.00	Barking Power	CCGT
BARK82	1	0.00	Barking Power	CCGT
BARK83	3	0.00	Barking Power	CCGT
BARK84	1	0.00	Barking Power	CCGT
DEES81	4	3.72	PowerGen	CCGT
DEES82	2	8.00	National Power	CCGT
DEES83	1	8.00	National Power	CCGT
EASO81	2	8.00	National Power	CCGT
EASO82	1	8.00	National Power	CCGT
MEDW81	3	3.72	Medway Power	CCGT
MEDW82	1	3.72	Medway Power	CCGT
RYEH81	3	3.57	PowerGen	CCGT
RYEH82	1	3.57	PowerGen	CCGT
SEAB81	6	3.72	Humber Power	CCGT
SEAB82	3	3.72	Humber Power	CCGT
SUTB81	2	3.72	Independent Power Generators Ltd	CCGT
SUTB82	2	3.72	Independent Power Generators Ltd	CCGT
BLYT81	2	9.50	National Power	Medium coal
BLYT82	4	15.94	National Power	Small coal
RATS81	2	4.92	PowerGen	Large coal
RATS82	2	4.92	PowerGen	Large coal
WBUR81	4	8.58	National Power	Large coal
INCE81	1	4.47	PowerGen	Oil
INCE82	1	4.47	PowerGen	Oil
KINO81	4	32.64	PowerGen	Large coal
FIDF81	1	9.52	PowerGen	Large coal
FIDF82	1	9.52	PowerGen	Large coal
FIDF83	1	9.52	PowerGen	Large coal
TORN81	2	4.99	Scottish Power	Nuclear
HUER81	2	4.99	Scottish Power	Nuclear
LOAN81	4	4.99	Scottish Power	Medium coal
LOAN82	4	4.99	Scottish Power	Medium coal
COCK81	4	4.99	Scottish Power	Medium coal

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Station busbar code	Maximum number of units	Pool offer price £/MWhr	Owner	Plant type
CHAP81	8	0.00	Scottish Power	Nuclear
CRUA81	1	4.99	Scottish Power	Small coal
CRUA82	2	4.99	Scottish Power	Small coal
GLLE81	2	4.99	Scottish Power	Hydro
PEHE81	2	1.50	Scottish HE	Large coal
SHIN81	3	1.50	Scottish HE	Hydro
BEAU81	8	1.50	Scottish HE	Hydro
BEAU82	7	1.50	Scottish HE	Hydro
FAUG81	8	1.50	Scottish HE	Hydro
ERRO81	7	1.50	Scottish HE	Hydro
ERRO82	6	1.50	Scottish HE	Hydro
KEOO81	2	4.99	Scottish Power	Hydro
TONG81	1	4.99	Scottish Power	Hydro
KIIN81	7	1.50	Scottish HE	Hydro
SLOY81	8	1.50	Scottish HE	Hydro
LEVE81	2	4.99	Scottish Power	Hydro
FASN81	4	1.50	Scottish HE	Hydro

Table D.4: Randomly generated merit orders used during case study 4 of chapter 7

Station busbar code	Pool offer price for study 'random #'									
	1	2	3	4	5	6	7	8	9	10
HEYS81	29.8	6.3	82.7	59.1	35.5	12.0	88.4	64.8	41.3	17.7
HINP81	71.5	10.7	49.9	89.1	28.4	67.6	6.8	46.0	85.2	24.4
HINP82	3.3	66.5	29.7	92.9	56.1	19.3	82.5	45.6	8.8	72.0
HINP83	87.4	29.0	70.5	12.0	53.5	95.0	36.5	78.0	19.5	61.1
WYLF81	53.4	67.8	82.2	96.6	11.0	25.4	39.8	54.2	68.6	83.0
HATL81	63.2	34.4	5.7	76.9	48.2	19.4	90.7	61.9	33.2	4.5
HATL82	89.1	17.3	45.4	73.6	1.8	30.0	58.1	86.3	14.5	42.6
DUNG81	25.8	72.3	18.8	65.4	11.9	58.5	5.0	51.5	98.1	44.6
DUNG82	93.2	94.0	94.9	95.7	96.6	97.4	98.2	99.1	99.9	0.8
SIZE81	27.7	96.1	64.4	32.7	1.0	69.4	37.7	6.0	74.3	42.7
GRST81	71.6	54.6	37.6	20.6	3.6	86.6	69.6	52.6	35.6	18.6
GRST82	48.3	44.9	41.5	38.1	34.7	31.3	27.9	24.5	21.1	17.7
GRST83	53.1	15.8	78.5	41.1	3.8	66.5	29.1	91.8	54.5	17.1
GRST84	18.3	9.8	1.3	92.8	84.3	75.8	67.3	58.8	50.3	41.8
SALH81	27.1	43.4	59.6	75.8	92.1	8.3	24.5	40.8	57.0	73.2
SALH82	60.3	66.1	71.9	77.7	83.5	89.3	95.1	0.9	6.6	12.4
RUGE81	83.3	32.7	82.1	31.5	80.9	30.3	79.6	29.0	78.4	27.8
DRAX81	22.8	18.0	13.3	8.5	3.7	98.9	94.2	89.4	84.6	79.9
DRAX82	66.8	36.3	5.8	75.2	44.7	14.1	83.6	53.1	22.5	92.0
EGGB81	52.9	47.6	42.3	37.0	31.7	26.4	21.1	15.8	10.5	5.2
EGGB82	53.4	22.7	91.9	61.1	30.4	99.6	68.9	38.1	7.3	76.6
DIDC81	15.2	58.3	1.5	44.6	87.7	30.9	74.0	17.1	60.2	3.4
IRON81	8.0	52.1	96.3	40.4	84.5	28.7	72.8	16.9	61.0	5.2
FERR81	53.4	43.1	32.7	22.4	12.1	1.8	91.4	81.1	70.8	60.4
FERR82	76.1	49.5	22.8	96.1	69.5	42.8	16.1	89.5	62.8	36.2
COTT81	79.1	84.3	89.5	94.7	99.9	5.1	10.3	15.5	20.7	25.9
SHBA81	67.6	72.8	78.0	83.2	88.4	93.6	98.8	4.0	9.2	14.4
SHBA82	38.4	4.5	70.6	36.6	2.7	68.8	34.9	1.0	67.0	33.1
KILL81	24.8	50.2	75.6	1.0	26.4	51.9	77.3	2.7	28.1	53.5
KILL82	73.2	28.6	84.0	39.4	94.7	50.1	5.5	60.9	16.3	71.6
KILL83	13.4	53.5	93.5	33.5	73.6	13.6	53.6	93.7	33.7	73.7
KILL84	52.1	89.5	26.9	64.2	1.6	39.0	76.4	13.8	51.1	88.5
KILL85	34.9	23.5	12.2	0.8	89.4	78.1	66.7	55.4	44.0	32.7
KEAD81	99.8	25.0	50.1	75.2	0.4	25.5	50.6	75.8	0.9	26.0
KEAD82	38.5	4.9	71.3	37.7	4.1	70.5	36.9	3.3	69.7	36.1
KEAD83	81.6	26.4	71.1	15.9	60.7	5.5	50.3	95.0	39.8	84.6
KEAD84	61.7	3.3	45.0	86.6	28.2	69.8	11.4	53.0	94.6	36.2
BARK81	79.6	57.3	35.0	12.7	90.3	68.0	45.7	23.4	1.0	78.7
BARK82	93.4	56.9	20.5	84.0	47.5	11.1	74.6	38.1	1.7	65.2
BARK83	3.2	97.7	92.1	86.5	81.0	75.4	69.9	64.3	58.8	53.2
BARK84	99.3	40.5	81.7	22.9	64.1	5.3	46.5	87.7	28.9	70.1
DEES81	92.2	72.7	53.1	33.5	14.0	94.4	74.9	55.3	35.7	16.2
DEES82	94.3	22.1	49.9	77.7	5.5	33.3	61.1	88.9	16.8	44.6
DEES83	7.0	29.2	51.4	73.6	95.8	18.0	40.2	62.4	84.5	6.7
EASO81	6.7	97.4	88.0	78.7	69.4	60.1	50.8	41.5	32.2	22.8
EASO82	89.4	62.3	35.3	8.3	81.3	54.3	27.3	0.3	73.3	46.3
MEDW81	83.1	5.0	26.9	48.8	70.8	92.7	14.6	36.5	58.4	80.3
MEDW82	9.0	93.4	77.8	62.2	46.6	31.1	15.5	99.9	84.3	68.7
RYEH81	12.7	2.7	92.8	82.8	72.8	62.9	52.9	43.0	33.0	23.0
RYEH82	62.2	71.7	81.1	90.6	0.1	9.5	19.0	28.4	37.9	47.4
SEAB81	3.0	1.9	0.9	99.8	98.8	97.7	96.7	95.7	94.6	93.6
SEAB82	85.0	1.4	17.7	34.1	50.5	66.8	83.2	99.6	15.9	32.3

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Station busbar code	Pool offer price for study 'random #'									
	1	2	3	4	5	6	7	8	9	10
SUTB81	95.8	60.3	24.9	89.4	53.9	18.5	83.0	47.5	12.0	76.6
SUTB82	74.0	27.9	81.8	35.7	89.7	43.6	97.5	51.4	5.4	59.3
BLYT81	49.3	7.0	64.8	22.6	80.3	38.1	95.8	53.6	11.3	69.1
BLYT82	77.7	16.8	55.8	94.9	33.9	73.0	12.0	51.1	90.1	29.2
RATS81	36.6	87.2	37.8	88.3	38.9	89.5	40.0	90.6	41.2	91.7
RATS82	3.5	41.5	79.6	17.7	55.7	93.8	31.8	69.9	7.9	46.0
WBUR81	49.0	24.1	99.2	74.3	49.4	24.5	99.6	74.8	49.9	25.0
INCE81	71.8	41.4	11.1	80.7	50.3	19.9	89.5	59.1	28.7	98.4
INCE82	1.4	31.1	60.7	90.4	20.0	49.7	79.3	9.0	38.6	68.3
KINO81	9.5	60.0	10.5	61.0	11.5	61.9	12.4	62.9	13.4	63.9
FIDF81	32.4	15.4	98.4	81.4	64.4	47.4	30.4	13.4	96.4	79.4
FIDF82	89.9	96.4	2.8	9.2	15.6	22.0	28.4	34.8	41.2	47.6
FIDF83	28.4	55.5	82.6	9.8	36.9	64.0	91.2	18.3	45.4	72.6
TORN81	79.4	81.9	84.5	87.1	89.6	92.2	94.7	97.3	99.9	2.4
HUER81	54.1	22.8	91.6	60.4	29.2	98.0	66.8	35.6	4.4	73.2
LOAN81	46.1	86.6	27.0	67.5	8.0	48.5	89.0	29.4	69.9	10.4
LOAN82	11.7	12.5	13.3	14.1	14.9	15.7	16.5	17.3	18.1	18.9
COCK81	37.8	81.0	24.3	67.5	10.8	54.0	97.3	40.5	83.7	27.0
CHAP81	77.2	61.1	44.9	28.8	12.7	96.6	80.5	64.4	48.3	32.2
CRUA81	74.3	39.3	4.3	69.2	34.2	99.2	64.2	29.1	94.1	59.1
CRUA82	10.1	15.3	20.5	25.7	30.9	36.1	41.3	46.5	51.6	56.8
GLLE81	4.6	64.6	24.6	84.6	44.6	4.6	64.6	24.6	84.6	44.6
PEHE81	50.0	45.7	41.4	37.2	32.9	28.6	24.4	20.1	15.9	11.6
SHIN81	68.4	21.3	74.1	27.0	79.9	32.8	85.6	38.5	91.4	44.3
BEAU81	19.4	98.0	76.6	55.2	33.8	12.4	91.0	69.6	48.2	26.8
BEAU82	34.1	24.3	14.5	4.7	94.9	85.1	75.3	65.5	55.7	45.9
FAUG81	4.1	36.0	67.9	99.9	31.8	63.7	95.6	27.5	59.4	91.3
ERRO81	98.4	32.7	67.0	1.3	35.5	69.8	4.1	38.4	72.7	7.0
ERRO82	42.4	97.1	51.7	6.4	61.0	15.6	70.3	24.9	79.5	34.2
KEOO81	64.1	31.3	98.4	65.5	32.7	99.8	66.9	34.1	1.2	68.4
TONG81	89.4	80.4	71.4	62.3	53.3	44.3	35.2	26.2	17.2	8.2
KIIN81	53.0	8.8	64.6	20.4	76.2	32.0	87.7	43.5	99.3	55.1
SLOY81	71.8	97.5	23.3	49.0	74.7	0.4	26.2	51.9	77.6	3.4
LEVE81	3.9	93.5	83.0	72.6	62.1	51.6	41.2	30.7	20.3	9.8
FASN81	19.7	74.1	28.5	82.9	37.2	91.6	46.0	0.4	54.7	9.1

Appendix E

Classical Machine Model Swing Equation

This appendix derives the classical swing equation, starting with the torque balance equation.

Machine accelerating torque is the difference between the mechanical torque input and the electrical torque output, i.e.

$$T_a = T_m - T_e. \tag{E.1}$$

Similarly, the accelerating power P_a is given by

$$P_a = T_a\omega = P_m - P_e \tag{E.2}$$

where ω is the machine angular velocity.

However, accelerating torque is related to the machine moment of inertia J and angular acceleration α

$$T_a = J\alpha \tag{E.3}$$

and angular momentum, M, is given by

$$M = J\omega. \tag{E.4}$$

Hence, inserting E.3 and E.4 into E.2 gives

$$P_a = (J\alpha)\omega = M\alpha = P_m - P_e. \tag{E.5}$$

Now,

$$\alpha = \frac{d^2\Theta}{dt^2} \tag{E.6}$$

where Θ is the angular displacement of the machine rotor. This can be written

$$\Theta = \omega t + \delta \tag{E.7}$$

so that

$$\alpha = \frac{d^2(\omega t + \delta)}{dt^2} = \frac{d^2\delta}{dt^2}. \tag{E.8}$$

Substituting E.8 into E.5 provides the usual swing equation:-

$$P_a = P_m - P_e = M\frac{d^2\delta}{dt^2} \tag{E.9}$$

Note that M is related to the machine inertia constant, H and the machine MVA rating, G by

$$M = \frac{2GH}{\omega_0} \tag{E.10}$$

where ω_0 is the system synchronous frequency. Note that the units of M are MJs/radian.

Appendix F

Published Papers

The following pages include papers published by the author and based on work contained in this thesis. They are

- **"Evaluation of Power System Stability Constraint Costs by a Monte Carlo Method"** presented at the *31st Universities' Power Engineering Conference* (UPEC), Crete, September 1996
- **"A Comprehensive Method to Estimate Power System Stability Constraint Costs"** presented at *International Power Engineering Conference* (IPEC), Singapore, May 1997

EVALUATION OF POWER SYSTEM STABILITY CONSTRAINT COSTS BY A MONTE CARLO METHOD

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Abstract

Power systems are now being operated closer to their stability limits. This occasionally requires that generation schedules should deviate from merit order operation to ensure an acceptable dynamic response in the event of unforeseen plant outages. A cost is incurred by this rescheduling, termed *stability constraint cost*. In planning time scales it is useful to weigh this cost against costs of network developments. This paper describes software designed to estimate stability constraint costs, combining Monte Carlo simulations of network conditions with a dynamic security assessor. A transient stability index is used to target those generation units which must be constrained.

1 INTRODUCTION

One of the primary objectives in the day to day operation of the UK National Grid system is the supply of electricity to consumers at a minimum cost. To meet this objective, available generation units are scheduled to provide active output by NGC, in *bid price* merit order. Ideally, the cheapest set of available generating units would be scheduled to meet system demand, known as operation in *merit order*. However, various operational limitations of the transmission network must also be taken into account. These limitations are known as *constraints*.

Many constraints have tended to be the result of thermal limitations of transmission plant. In other words, the power flow over part of the transmission network has had to be constrained to prevent the violation of the thermal ratings of plant. Reinforcements to the transmission system to improve thermal ratings have reduced the number of these *static* constraints. However, the result of this has been the emergence of stability limited power transfers, or *dynamic* constraints [1].

The effect of constraints is that operation in merit order is not always possible. To reduce power transfers below transmission limits, an amount of in merit generation must be *constrained off* and compensated for by *constraining on* out of merit generation. The cost of this action is known as the constraint cost. As part of its duty to run an efficient transmission system, the National Grid Company (NGC) seeks to keep constraint costs to an economic minimum. In the longer term, investment in new transmission plant can be considered if it is justified by a sufficient reduction in associated constraint costs.

The calculation of constraints takes into account the behaviour of the power network under credible system outages, or *contingencies*. For example, if four transmission lines, each rated at 1000 MW connect a power station to a load, to assure the system operates securely with up to two concurrent outages, the maximum transfer between the two is constrained to 2000 MW. It is more difficult to make this sort of assessment for dynamic constraints. The stability of the system needs to be tested at various values of power transfer, usually using a power system simulator. A constraint may then be imposed based on the results.

A planning tool has been developed within NGC, known as ESCORT [2], to estimate transmission constraint costs resulting from static security limitations. ESCORT has been adapted since its conception to crudely model stability constraints by the imposition of power transfer limited boundaries within the network. These limits are conservatively derived from system operator experience and simulator stability studies outside of ESCORT [3]. The result of this conservatism can be an over estimate of constraint costs possibly resulting in unnecessary investment in transmission plant.

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The need has therefore arisen for a tool which is able to provide a more accurate estimate of dynamic constraints. The software described in this paper addresses this problem. Like ESCORT, the basis of this tool is a simulation of day to day demand variation on a power system. Plant outages are simulated using a Monte Carlo model [4], such that only generation units typically available on the real system are used to meet demand. The new tool is known as CAMEL, which stands for *C*onstraint *A*nalysis using *M*onte Carlo *E*valuation of *L*oading.

The major difference between ESCORT and CAMEL is that whereas ESCORT utilises a DC load flow to find power flows on the simulated system, CAMEL uses a full dynamic simulation to assess system stability. Should a particular system configuration prove unstable, a new generation schedule is determined to restore stability. This is achieved by identifying those generating units contributing most to system instability and then realising a new, least cost schedule. Generation constraint cost can then be measured directly.

The next section of this paper is devoted to a description of the overall algorithm implemented by CAMEL. Some justification of method is given where appropriate along with examples of data and output. Section 3 gives results of a CAMEL simulation, particularly showing how the constraint algorithm arrives at a solution. Conclusions are drawn in section 4.

2 SOFTWARE METHOD

The overall principle is to test the stability of the system over a wide range of possible operating conditions. When unstable scenarios are encountered, the stability of the system is remedied on a least cost basis. This cost is found for all such unstable conditions to give a broad assessment of stability constraint costs.

The method implemented by the CAMEL software is shown diagrammatically in figure 1. Within a single study, CAMEL runs several Monte Carlo simulations, each of which involves scheduling available generation to meet system demand according to some specified merit order. Variation between simulations occurs for two reasons. Firstly, demand level is chosen statistically according to a *load duration* curve. Secondly, statistical availability trials are carried out on each generating unit for each simulation according to a set of statistical input data.

The stability of the system is tested after each Monte Carlo simulation using a dynamic security assessment (DSA) system. In cases where instability occurs, CAMEL uses data from time domain simulation to choose which generation units to constrain to prevent instability. The associated constraint cost is thereby measured directly from generation bid prices.

After individual simulations are complete, all data and results are collated by the CAMEL *master task*, analysed, and presented to the user.

The stages involved in the above process are described in more detail in the following subsections.

2.1 Network demand model

The system nodal demand distribution is taken from a single load flow study at a high demand level, say 90% Average Cold Spell (ACS). For each Monte Carlo simulation a demand level is then chosen probabilistically from a load duration curve. For instance, if 40-100% ACS demand occurs 85% of the time, a demand level of 40% ACS or above has an 85% probability of being chosen by the simulation. Nodal demands are scaled accordingly.

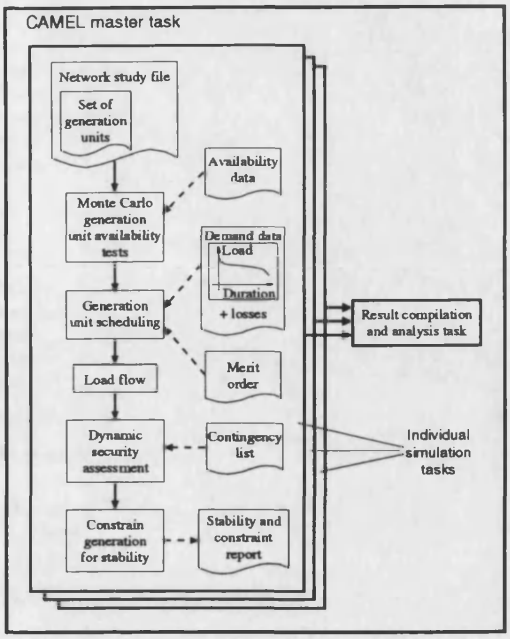

Figure 1: A diagrammatic representation of the method implemented by CAMEL, indicating the relation between individual Monte Carlo simulations and a whole CAMEL study.

	Overall availability including planned and forced outages			
	Winter	Spring	Summer	Autumn
CCGT units	91%	90%	86%	89%

Table 1: A sample set of availability data for combined cycle gas turbine (CCGT) generating units

2.2 Plant availability model

Projected generation availability data is categorised by season and plant fuel type. Thus, each generation unit is assigned a fuel type and CAMEL selects a season for each simulation. The Monte Carlo availability trials are then performed for each generating unit using the probability of availability for the corresponding season and fuel type.

Table 1 is an example of the form of availability data used. The figures account for both planned and forced outages, i.e. outages caused by routine maintenance and outages caused by plant failure respectively.

Transmission maintenance outages are currently ignored for the purposes of identifying additional investment. Transmission plant non-availability due to failure is also neglected as levels are typically less that 1%. Note, however, that contingencies afford the capability to study the effect of such outages at the security assessment stage.

2.3 Generation scheduling

A list of available generating units is obtained from the previous stage. These are ranked in ascending order of cost, i.e. *merit order*. An estimate of network losses is made, losses and demand are summed and generating units scheduled to meet this total load in accordance with the merit order. All generating units which are scheduled on are set to their maximum MW output with the exception of the *marginal unit*, illustrated in figure 2. The output of this unit is set to meet the remaining deficit between load and generation. When the load flow stage is

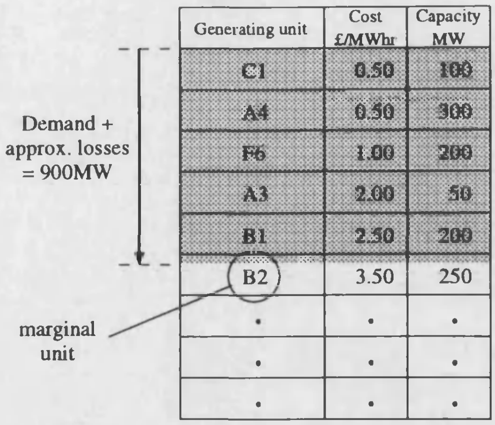

Figure 2: An example of generation units being scheduled from a merit order, highlighting the *marginal unit*

run, the busbar to which this unit is connected becomes the 'slack bus'.

2.4 Security assessment

The first stage of the security assessment task is to attain a converged load flow solution. The load flow program used by CAMEL is OPFL02 [5], a comprehensive package provided by NGC.

Security is assessed using a fast parallel DSA. This package incorporates complex control system models and uses a state-of-the-art rapid time domain simulator to analyse the performance of a large power network for a list of credible system faults, or contingencies [6].

The DSA classifies results by analysing the rotor angle swings of all the generating units in the system after the onset of each contingency up until the termination of the time simulation, typically 15-30s later. If a contingency causes any unit to pole slip during the simulation, that contingency is classed '*PS*'. Similarly, if any unit produces building rotor oscillations, but no pole slip is detected during the time simulation, this is classed '*DI*' which signifies divergence. Bad damping (*BD*) is also detected, characterised by rotor angle oscillations with a decay time constant greater than 12s. This is consistent with operational practice that all rotor angle oscillations should be negligible 60s after a contingency.

Because transient stability is dependant on the disturbance applied to the system, it is important that the list of contingencies used at this stage relates to generation constraints of interest. Often such contingencies will include faults on 'weak' interconnections in the system. Past experience gained by planning engineers, or a few preliminary studies using a large list of contingencies, is beneficial in identifying a suitable set of contingencies.

2.5 Generation constraints

When a stability problem is encountered, a new, stable, least cost generation schedule is found. This is achieved using the algorithm detailed below. The basis of the algorithm is an individual generation unit *transient stability index*, or TSI. The criterion for choice of a suitable TSI is simply that it should order the generation units in the system according to which units restore stability for the least change in power output. The TSI used at present is a product of two indices; a *transient energy function* index (TEFI) and a *contribution* index (CI).

The TEFI is calculated directly from the time domain responses of individual generating units, as suggested by Tang et al in ref. [7]. This approach avoids the need to replace complex machine and control system models with their classical counterparts, which can tend to limit the accuracy of results. Transient potential energy is found with the formulation of the continuous time integral described in ref. [8].

The CI is included in the TSI as a means of establishing the extent to which the power output of a generating unit is disturbed by the faulted power flows in the system. The algorithm which is used to determine a generation unit's contribution is an adaptation of that described by Kirschen et al in ref. [9]. Effectively, the power flows across all transmission plant feeding a fault are summed, and the proportion of that flow provided by each generation unit determined. The per unit CI for each generation unit is then given by:-

$$CI = \frac{faulted\ power\ flow\ from\ unit}{unit\ output} \tag{1}$$

Both the CI and TEFI are calculated during the initial run of the time domain simulation which is necessary for stability assessment. Computational requirements for the TEFI are low as it is not necessary to calculate the *transient energy margin* [10]. Stability assessment is made solely from the time domain simulation.

ALGORITHM

For an unstable contingency, do:

1. Sort generation units into categories A and B according to power in-feed to fault. Group A contains those which contribute to the faulted power inflow while group B contains the remainder.

2. Sort generation units of group A into a list in ascending order by the transient stability index. Sort generation units in group B into a list using their pool bid prices.

3. Constrain off the most effective generation units from the top of list A and make up the associated generation deficit by constraining on the least expensive *available* generation units from the bottom of list B.

4. Test previously unstable contingency using the DSA to see if stability is restored. If not, the algorithm returns to step 3.

REMARKS

The process by which cost optimality is incorporated into the above algorithm is as follows. Generation units in list A are only ordered by the TSI. Hence, the units at the top of the list require the smallest reduction in MW to restore stability. Provided these units are also the cheapest to constrain, i.e. have the highest bid price, then the least value of constraint cost has been found. However, it may be that there are other units lower down list A with a higher bid price. Although they will need to be constrained by a larger number of MW to restore stability, the constraint cost could therefore be less. These alternative units are tested in the order they appear in the list, with the ongoing minimum constraint cost being stored for comparison purposes.

After the generation schedule has been constrained for a single contingency, all other contingencies must also be tested to make sure that the schedule does not introduce new stability problems.

ASSUMPTIONS AND SIMPLIFICATIONS

- With the exception of slack bus generation, all other generation units, if scheduled, run fully loaded. This is generally consistent with current day-ahead plant scheduling practice.

- Required changes to the unconstrained generation schedule to ensure stability are assumed to be small. Large changes would indicate unacceptable constraint costs and would incur computation time penalties within the framework of this algorithm.

- It is assumed that a single stable generation schedule may be found for all contingencies. A contrary result would indicate that the network configuration is not securable.

2.6 Control of multiple simulations

Initiation of individual Monte Carlo simulations and collation of results is performed by the *CAMEL master task*. All data generated by the individual simulations is stored by the CAMEL master task for subsequent analysis. This includes generation pattern and the stability report.

The main criteria which is used to assess and analyse the system's stability is a *badness* index. This is derived empirically from the results for each contingency. After several individual simulations a picture is built up of the statistical probability of a contingency causing a stability problem. The badness index is then found with the formula,

$$Badness = \frac{(\frac{(100-a)}{2} + d)PS + (\frac{(100-a)}{2} - d)DI + aBD}{(\frac{(100-a)}{2} + d)} \tag{2}$$

where d is the duration of the time simulation and PS, DI and BD are the percentage probabilities of a pole slip, divergence and bad damping respectively. a is the maximum percentage of the total badness index that may be attributed to bad damping. The value of a is empirically set to 10 at present. The duration of the simulation is included in this formula to reflect that diverging cases would tend to diverge to a pole slip for a longer simulation duration. Note that a 100% probability of a pole slip gives a badness index of 100%.

An overall badness index for the study is found by averaging the indices for each contingency. An appropriate set of confidence limits is calculated so that an estimate may be placed on the accuracy of the badness index. The index is used throughout a CAMEL study by the master task. The index is monitored at the end of each simulation. If the sum of the badness index and its confidence interval is outside limits specified by the user, the study will stop prematurely. This can represent a significant saving in time as the user does not have to wait until the completion of the whole study to find that the results are either unacceptable or unimportant.

2.7 Compilation of results

The CAMEL master task is responsible for compiling the results from all the simulations into a study report for the user, an example of which can be seen in figure 3. The results are broken down by contingency, so that the contribution of each to the overall stability of the system can be appreciated. This can also provide useful insights into the contribution of each contingency to constraint costs. However, it is worth noting that the constrained generation schedule calculated for each *simulation* satisfies all contingencies. It is therefore not possible to assign a proportion of the constraint cost to each contingency. However, should a contingency prove 100% stable, it clearly has no effect on generation constraints.

Other summary data is presented to the user, including the probability of a simulation being unstable, and most importantly, an average constraint cost. The latter is an average of the constraint cost found for each individual simulation over the whole study.

3 RESULTS

The implementation of the above method is demonstrated by a walk through of the results from a single simulation. The power network used is a planning scenario based on the UK National Grid System. The system has around 900 busbars and 1800 lines. A total of 87 power stations, each with between one and eight generating units are specified as able to meet system demand.

The simulation task selects a demand level of 72% ACS. The load on the system is 39.6GW with losses estimated by the simulation to be 800MW. The required level of generation is thus 40.4GW. An outage period corresponding to the months of March and November is selected. The Monte Carlo outage simulation results in sixteen generation units unavailable. 67 power stations are required to meet the demand,

```
(C)onstraint (A)nalysis using (M)onte Carlo (E)valuation of (L)oading

PSSEng time step is 5ms and simulation duration is 12s

CAMEL running ...
Finished running study 0100

Results obtained from 100 studies of 4 contingencies

Ct.   Name                          %PS    %DI    %BD    %BN +/- L

   4 Contingency D                  26.0   28.0   11.0   44.1 +/-  8.0
   3 Contingency C                   0.0   35.0    9.0   21.8 +/-  5.3
   1 Contingency A                   0.0    7.0    9.0    5.6 +/-  3.0
   2 Contingency B                   0.0    0.0    0.0    0.0 +/-  0.0

Key:    PS = Pole slip
        DI = Diverging, but no pole slip detected in 12s
        BD = Badly damped
        BN = Badness index for contingency
        L  = 95% Confidence limits of badness index
Average badness of study is 17.9+/-4.1 %
Probability of a stability problem is 65.0%
Average constraint cost £   383.52/hr
```

Figure 3: Sample results from the CAMEL program for 100 simulations using a list of 4 critical contingencies.

Station name	Indices			Bid price £/MWhr	Avail. units
	TEFI	CI	TSI		
GEN-71	2.51	0.32	0.803	10.3	2
GEN-67	0.69	0.26	0.179	11.5	4
GEN-69	1.23	0.13	0.160	1.5	2
GEN-68	1.08	0.13	0.140	1.5	2
GEN-66	0.48	0.28	0.134	1.0	4
GEN-75	1.99	0.03	0.060	0.0	2

Table 2: The top of the ranked list of groups to be constrained off to restore stability for a single contingency.

making the most expensive generation unit in merit £12.90/MWhr, i.e. the *system marginal price* is £12.90/MWhr.

A constraint boundary of interest to NGC is to be studied. Four contingencies, known by planning engineers to be problematic in the context of this constraint, are used for the DSA task. It is found that one of the contingencies is transiently unstable. Eleven power stations are identified as contributing to the faulted power flow for this contingency. The first six of these are shown in table 2.

The first iteration of the constraint algorithm finds that if one unit is constrained off at GEN-71, stability is restored. The generation constraints are shown in table 3. The total constraint cost of this action is £10,480/hr. Because GEN-67 has a higher bid price, it is possible that although a larger number of MW must be constrained off, the cost will be less. Hence, the constraint algorithm tests this hypothesis. The cost is determined in the same manner as for GEN-71, and found to be £11,230/hr. Thus, the former and less expensive of the two sets of constraints is used. The resulting generation schedule is tested by the DSA with the set of remaining contingencies and found to be stable.

Station name	Constrained On (MW)	Constrained Off (MW)	Bid price £/MWhr	Cost £/hr
GEN-71	-	665	10.3	1729
GEN-60	571	-	13.2	7537
GEN-61	94	-	12.9	1213
			Total	10479

Table 3: Constraint actions to restore stability for a single contingency.

4 CONCLUSIONS

A viable stability constraint costing method has been described and demonstrated in this paper. The core of the method is an automatic generation constraint algorithm based around a fast dynamic security assessor. Reliability is not compromised as detailed time domain simulation is used for stability assessment purposes. Indices derived from this simulation are then used to determine suitable constraint actions. Sensible assumptions and simplifications are made in order to reduce the search space of the constraint algorithm.

The software used to implement this method should save planning engineers time and provide greater insights into the causes of constraint costs while also indicating how they may be reduced. This should be beneficial in maintaining a tighter control over such costs in the long term.

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A COMPREHENSIVE METHOD TO ESTIMATE POWER SYSTEM STABILITY CONSTRAINT COSTS

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Abstract

Power systems are now being operated closer to stability limits and sometimes generation schedules must deviate from merit order operation to give an acceptable dynamic response in the event of possible contingencies. A cost is incurred by this rescheduling, termed the *stability constraint cost*. In planning time scales it is useful to weigh this cost against the cost of network development. This paper describes software designed to estimate stability constraint costs, harnessing Monte Carlo techniques with fast dynamic security assessment. A set of indices which characterise the system stability is used to target those generation units which must be constrained for unstable scenarios.

1 INTRODUCTION

An important aspect of system operation is the coordination of generating plant, such that the total system demand is met at a minimum cost. Ideally, the cheapest set of active generation would be chosen to meet the demand on the system, known as operation in *merit order*. However, in practice, there are certain limitations on the transmission system which sometimes prevent this being the case. These limitations are termed *constraints*. In the past, most constraints have been due to plant thermal capacity limits being reached. More recently, as transmission systems have been reinforced to overcome these thermal limitations, *voltage and stability* constraints have emerged as a larger problem [1].

In the event of a constraint, in-merit generation must be *constrained off* and other more expensive generation constrained on. The total cost of these actions is known as the *constraint cost*. An appreciation of constraint cost is very useful to a planning engineer when assessing the cost benefit of modifications to the power system.

Traditional methods for examining constraint costs arising from thermal limitations rely on the use of a DC network model. Linear programming techniques can then be used to find a least cost solution to thermal transfer violations [2]. The transfer capability of a power system must be examined with the system subject to a predetermined set of fault events or *contingencies*. Analysis of such conditions is again well suited to the linear DC model. However, to incorporate voltage and stability constraints is difficult. Conservative transfer limits derived from external dynamic simulations must be imposed across critical power system boundaries. Derivation of these boundary stability limits is very time consuming because each boundary limit may approximate the cost effectiveness of constraining different generators within the boundary for a restricted set of flow conditions.

This paper describes an approach to estimating the stability constraint costs. A full dynamic simulation for each of a list of contingencies enables problematic network operating conditions to be identified. In the event of a contingency proving unstable under an initial generation schedule, a low cost change to the generation schedule is implemented to restore stability. By using a dynamic simulation at this stage, an explicit measure of stability constraints can be obtained yielding a more accurate estimate of stability constraint costs.

In order to ensure that cost estimates arrived at in the planning studies are representative of the uncertainties and diversities on the future system, a variety of different plant and demand patterns are studied by employing Monte Carlo techniques.

The focus of this paper is the algorithm used to determine the generation constraints necessary to restore system stability, described in section 2.4 and the appendix. The rest of the software is treated in more detail in [3]. Section 2 provides a broad overview of the whole software, known as CAMEL (*C*onstraint *A*nalysis using *M*onte Carlo *E*valuation of *L*oading). Section 3 illustrates the use of the software on a particular planning scenario. Conclusions are made in section 4.

2 THE SOFTWARE - CAMEL

2.1 Overview

A single CAMEL study run aims to test the stability of a power system over a broad range of operating conditions, thereby yielding a constraint cost which is representative of the uncertainties and diversities existing in the future system. To achieve this, a specified number of individual Monte Carlo simulations are performed, see figure 1. For each of these simulations, a level of network demand is chosen. In addition, outages of generation plant caused by routine maintenance and random breakdown are modelled. The stability of the system is tested for each simulation using a fast dynamic security assessor. When an

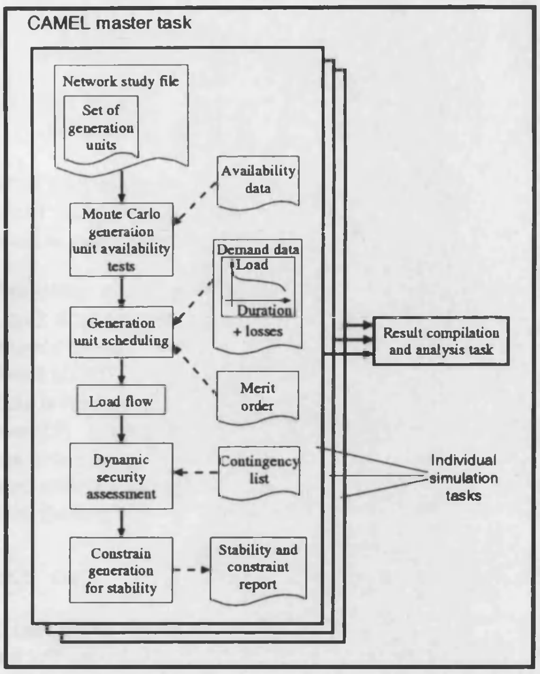

Figure 1: A diagrammatic representation of the CAMEL algorithm.

unstable scenario is encountered, a constraint algorithm is used to select appropriate changes to the generation schedule to restore stability. The corresponding constraint cost is then calculated.

The *CAMEL master task* coordinates the individual Monte Carlo simulations. When complete, the results of all individual simulations are collated and presented to the user in a structured and condensed form.

2.2 Demand model and Generation scheduling

A load duration curve is probabilistically sampled for each Monte Carlo simulation run. A percentage of average cold spell (ACS) demand is thereby chosen and the demand at each load point in the system scaled appropriately.

Monte Carlo trials are then performed on each generating unit in the system to determine whether or not they are available to meet the current system demand. The outage data used for these trials includes both planned and forced outage rates, categorised by season of the year and plant fuel type. For example, a unit in a coal fired power station might have an 88% chance of being available in the winter season. CAMEL selects a season for each individual simulation based on the duration of that season in the whole year. So if the winter season is 3 months long, CAMEL will choose to use the winter plant outage rates for 25% of all simulations.

The remaining available generating units are now used to meet demand. An estimate of system losses is made and added to the demand. The available generating units are initially scheduled to run in order of their position in the merit order. A single unit in the final set of utilised, available generation will be part loaded at this stage, i.e. the *marginal unit*. The cost price per MWhr or *bid price* of this unit sets the *system marginal price* (SMP).

2.3 Security assessment

The first stage of the security assessment task is to obtain a converged load flow. This is achieved using OPFL02, an AC load flow package provided by the UK National Grid Company (NGC). The slack bus is set to the marginal unit so that any error in the estimate of system losses can be balanced by a change in generation there.

Security is assessed using a fast dynamic security assessment (DSA) package incorporating complex control system models. A state-of-the-art rapid time domain simulation is used to analyse the performance of the power network for a list of contingencies [4].

The DSA classifies results by analysing the rotor angle swings of all the generating units in the system after the onset of each contingency up until the termination of the time simulation, typically 15-30s later. If a contingency causes any unit to pole slip during the simulation, that contingency is classed '*PS*'. Similarly, if any unit produces building rotor oscillations, but no pole slip is detected during the time simulation, this is classed '*DI*' which signifies divergence. Bad damping (*BD*) is also detected, characterised by rotor angle oscillations which decay with a time constant greater than 12s. If a pole slip is detected, the simulation will be stopped to save computing time.

2.4 Generation Constraints

When an unstable generation and demand pattern is encountered, a new generation schedule must be found while trying to keep the cost of any changes to a minimum. This is achieved in CAMEL using the following algorithm.

2.4.1 Single contingency constraints

For an unstable contingency,

1. Divide the available generating units in the system into two categories, A and B. A contains all the generating units which improve system stability when constrained off. B contains the remainder.

2. Rank generating units in category A by their ability to provide the largest improvement in system stability for the smallest change in active output. This is described in the appendix. Rank the generating units in category B by bid price.

3. Reduce the output from the most effective generators from rank A and balance the generation change by

constraining on the least expensive generation from rank B.

4. Test system stability using the DSA. If the system is still unstable, return to step 2.

After each constraint action, the stability of the system is tested using the DSA. This ensures that any solution arrived at meets stability requirements.

The value of the generation constraint implemented in step 3 is set small enough to keep stability effects approximately linear. From experience, a maximum value of about 100MW was found to be practical for large systems. This is consistent with the findings of Fouad et al in reference [5]. If additional accuracy is required, the step size can either be reduced, or a binary search technique can be used with the 100MW range as a starting point. However, both these solutions have run time implications.

2.4.2 Cost

If the stability of the system can be restored by constraining off one generation unit only, it may be possible to find a more cost optimal solution by choosing an alternative unit with a higher bid price. This is because the cost of constraining off a generation unit is given by $(SMP\text{-}bid\ price).g$, where g is the number of MW to be constrained. Hence, if the position of a generating unit in rank A is lower than that of the selected unit, but its bid price is higher, it should be tested to see if it will restore stability at a lesser cost. An example of this approach is given in the results section of reference [3].

It should be noted that the larger component of constraint cost is the constrained-on-cost. This is because the payment made for constrained-on-generation is simply $(bid\ price).g$. As this generation is out of merit, the bid price will be greater than SMP. Thus, the cost of constrained-on generation makes a larger contribution to the total constraint cost than the constrained-off generation. Hence, although true minimisation of constraint cost is not possible without taking into account the bid price of the generation to constrain off, by trying to minimise g, the larger proportion of the cost will be kept as small as possible. This is the policy adopted by this algorithm for unstable cases requiring multiple generator constraints.

2.4.3 Dealing with multiple unstable contingencies

Occasionally, more than one contingency will be unstable for a given demand/generation pattern. In these circumstances, it is necessary to try and find a generation pattern which is stable for all contingencies. This is achieved by amalgamating all the stable generating patterns obtained for single contingencies. In the final generation schedule, the largest 'constrain-off-action' for each generation unit will be selected. The resulting shortfall in generation is made up by constraining on the least expensive units from the remaining available generation. Some typical constraint actions are given in the example output file shown in figure 2.

```
Constraints for study 14

Group GEN-19 constrained on  by  130.0MW at a cost of £1417
Group GEN-66 constrained off by   20.0MW at a cost of £ 188
Group GEN-67 constrained off by  110.0MW at a cost of £1034

Total cost of constrained on  gen = £   1417 /Hr
Total cost of constrained off gen = £   1222 /Hr

Total constraint cost             = £   2639 /Hr
```

Figure 2: An example of a constraint action CAMEL output file.

2.5 Collation of results

Collation of results is performed by the CAMEL master task. An empirical performance index, called the *badness index* is used to monitor the overall results of a CAMEL study while it is still in progress. This is useful as it allows for early termination of the study if the number of stability problems is either unacceptably high, or low enough not to be of concern. Confidence limits are calculated for the badness index, so that a maximum and minimum value may be assigned. Should these values fall outside user defined tolerances, the CAMEL study will be halted.

The badness index is defined as the sum across all contingencies of,

$$Badness = \frac{(\frac{(100-a)}{2} + d)PS + (\frac{(100-a)}{2} - d)DI + aBD}{(\frac{(100-a)}{2} + d)} \quad (1)$$

where d is the duration of the time simulation and PS, DI and BD are the percentage probabilities of a pole slip, divergence and bad damping respectively. a is the maximum percentage of the badness index which may be attributed to bad damping. The value of a is empirically set to 10% at present. The duration of the simulation is included in this formula to reflect that diverging cases would tend to diverge to a pole slip for a longer simulation duration. Note that a 100% probability of a pole slip gives a badness index of 100%.

2.6 Program output

Results from all simulations are compiled into a summary report of the form of figure 3. This lists the percentage probabilities of each of the contingencies studied causing a pole slip, divergence or bad damping. The individual badness of each contingency is also given, and this is used to rank all contingencies. This format enables the user to see how each contingency contributes to the overall stability problems on the system. The cost of securing each contingency is also given, although it is worth noting that several contingencies may have constraint actions in common, so that the total cost of securing all contingencies may be less

```
(C)onstraint (A)nalysis using (M)onte Carlo (E)valuation of (L)oading

CAMEL running ...
Finished running study 0100 : time to completion 00:00:00 : badness   2.2

Results obtained from 100 simulations of 4 contingencies

Ct.  Name                 %PS    %DI    %BD    %BN +/- L      Cost

  1 CONTINGENCY A         4.0    0.0    0.0    4.0 +/-  3.9 £   573k
  2 CONTINGENCY B         0.0    0.0    2.0    0.4 +/-  0.5 £   213k
  4 CONTINGENCY D         0.0    0.0    0.0    0.0 +/-  0.0 £     0k
  3 CONTINGENCY C         0.0    0.0    0.0    0.0 +/-  0.0 £     0k

Key:    PS = Pole slip
        DI = Diverging, but no pole slip detected in 12s
        BD = Badly damped
        BN = Badness index for contingency
        L  = 95% Confidence limits of badness index

                    Summary
                    -------

Average badness of study is                   1.1+/-1.1%
Probability of a stability problem is              4.0%
Average constraint cost over study is      £626.603k/yr
```

Figure 3: Sample results from the CAMEL program for 100 simulations using a list of 4 critical contingencies.

than the sum of the cost of securing each contingency individually.

Other summary data is also presented to the user. This includes the probability of an individual simulation being unstable and an average constraint cost per simulation across the whole CAMEL study. If sought, detail about demand level, plant outages and constraint actions are all available to the user in files generated by the individual simulations.

3 RESULTS - CASE STUDY

Use of the software is described with reference to a planning scenario based on the UK National Grid System. The system contains about 900 nodes and 1800 lines. There are a maximum of 87 generating stations which may be used to meet system demand and losses.

The export from a particular part of the system, containing a large group of generating stations, is known to be stability limited. After certain proposed system reinforcements, a stable export value of EX MW was found by conventional planning methods. CAMEL was applied to examine the problem in detail. Three questions were to be answered:-

1. Is the value of export determined using conventional planning methods conservative, and by how much?
2. What constraint costs would be incurred by increasing the export above a value for which all scenarios are stable?
3. What constraint costs would be incurred if a particular system reinforcement is not made?

The system was studied initially using a list of nine contingencies, as selected by planning engineers. This list was further reduced to four contingencies which were found to limit the export capability. A load duration curve and generation bid prices were taken from published data [6]. Typical plant availabilities were also entered into CAMEL. 100 individual simulations were used for each CAMEL study.

System description	Export	Prob. of stability problem	Constraint cost £k/yr
System A:	EX	1	18
without	EX+100	3	338
reinforcement	EX+200	13	1,167
System B:	EX	0	0
following	EX+100	1	71
reinforcement	EX+200	4	627

Table 1: Constraint costs for values of export with unreinforced and reinforced planning scenarios.

Studies were run with the export set to EX, EX+100 and EX+200 for both the system without reinforcement (system A) and the system following reinforcement (system B). Results are shown in table 1. At an export of EX, system A was unstable in 1% of cases, giving a constraint cost of £18k/yr, while system B was stable under all conditions tested by CAMEL, giving zero constraint cost. At EX+100, system B was also unstable in 1% of cases, this time at a cost of £71k/yr. By performing studies with the export between EX and EX+100, the maximum stable export for system B was found to be EX+60. The stable export limit for system A was similarly found to be EX-20.

Note how rapidly the constraint cost rises for both systems as the stable export limit is exceeded. With this in mind, it can be appreciated that some degree of conservatism is prudent when setting export limits, especially when the bounds of accuracy of power system modelling is taken into account.

Note also that it is possible to make quantitative judgements about the value of the reinforcement present in system B. For instance, it could be said that the reinforcement is worth £(338-71)k at an export of EX+100 for the year studied.

4 CONCLUSIONS

The Monte Carlo framework implemented in CAMEL ensures that a variety of demand levels and plant patterns are studied. In itself, rapid determination of the likelihood of stability problems arising from a planning scenario represents a significant step forward. In particular, it can help to identify onerous demand levels and plant patterns which should be examined in more detail. However, with CAMEL it is possible to go one stage further and make an estimate of stability constraint costs.

The algorithm presented in section 2.4 details the method used to find low cost constraint actions when stability problems are encountered. The algorithm uses sensitivities of power system statistical composite indices to identify the best generators to constrain. This is a fast method because the indices are measured at the contingency termination point. Reliability is not compromised as all solutions found by the constraint algorithm are tested using full time domain analysis.

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APPENDIX: DETERMINATION OF GENERATION RANK

The constraint algorithm described in section 2.4 requires the generation units in the system to be ranked by their ability to restore system stability for the smallest change in active output power. To do this using time domain simulation coupled with a suitable search technique would be too computationally intensive for practically sized systems. In addition, there are instances where it is necessary to constrain a set of generating units to restore system stability. Under these circumstances, time domain simulation alone cannot provide the sensitivity information required.

Transient Energy Function (TEF) is commonly used in this area [5], but has not been selected for this work for two reasons:-

- TEF is only effective for first swing instability. Subsequent swing instability is also a significant problem in many systems.
- For systems including complex plant models, accurate results are best obtained using a technique known as *hybrid simulation* [7]. The problem with this method, is that time domain simulation must typically be run for several seconds after a contingency sequence, making it quite computationally expensive.

The method described here is based on the sensitivity of various *composite indices* derived from the power system state. Instead of simply using raw elements of this state as indices, a dimensionality reduction is made. This is beneficial because it ensures that the generality of the method is preserved across different loading levels and system topologies. Edwards et al demonstrated in reference [8] that composite indices are highly efficient for performing stability classification tasks. Therefore, the sensitivity of such indices with respect to the active output of generation should point to those units which it would be most effective to constrain.

The indices are measured at the *contingency termination point* (CTP), i.e. when all network topology changes are complete. The need for subsequent time domain simulation is thereby negated.

4.1 Selection of indices

A rank for each generating unit in the system is found for each of a set of contingencies. This is done as follows: A clearing time (CT) just greater than the critical clearing time (CCT) is determined for each contingency. The amount by which each generating unit in the system must be constrained to restore stability is then found using binary search. The generating units are ranked by the size of the constraint, least first.

A value of CT just greater than the CCT is used because changes in the output of a single generator to restore stability should be sufficient. Also, behaviour of the system with respect to small changes in generation can be approximated by linearisation. This is important because the linear sensitivities of power system parameters are to be compared with the results obtained from this procedure.

Next, the sensitivity of indices to perturbations in the output of each generating unit in the system are found and used to rank each unit. Finally, indices are selected by testing their ability to rank the machines in the same order as the time domain analysis described above. The following error function is used to perform this task:-

$$\varepsilon_I = \sum_{i=1}^{c}\sum_{j=1}^{m} \left|R_{C_{ij}} - R_{I_{ij}}\right|^N \qquad (2)$$

where ε_I is the error for index I, c is the number of contingencies studied, m is the number of generating units, $R_{C_{ij}}$ is the rank of generating unit j for contingency i found using time domain analysis. $R_{I_{ij}}$ is the rank of generating unit j for contingency i found using the sensitivity of index I.

N can be changed to affect the degree of penalisation the index suffers for large errors in single values of $R_{I_{ij}}$. It has been found that $N = 2$ selects indices which give good overall results.

4.2 Use of selected indices

A set of indices has now been selected which are able to perform the ranking task over a set of typical operating conditions and a number of contingencies. Although this process is time consuming, it need not be repeated for the same system. The indices can now be used to rapidly determine which generating units it is best to constrain without the need for lengthy time domain simulations. The rank of each unit is simply determined from,

$$\bar{R}_{ij} = \frac{1}{N}\sum_{I=1}^{N} W_I.R_{I_{ij}} \qquad (3)$$

where W_I is a weight for each index found from its error, ε_I, according to

$$W_I = \frac{1}{1+\varepsilon_I} \qquad (4)$$

4.3 The indices

The form of the indices is best described using set notation. Each index, I, is the intersection of six set members:-

$$I = A \wedge B \wedge C \wedge D \wedge E \qquad (5)$$

where A, B, C, D, E are members of the sets U_a, U_b, U_c, U_d and U_e respectively.

Parameter	Plant type		
	Busbar	Line	gen. unit
Voltage magnitude	*	*	*
Voltage phase	*	*	*
Loading		*	*
MW		*	*
MVAr		*	*
Power factor		*	*
MVAr losses		*	
AVR voltage error			*
Rotor angle			*
Rotor speed			*
Rotor acceleration			*
Kinetic energy			*
Momentum			*
Time to pole slip			*
Accelerating power			*

Table 2: Table of plant parameters used to form indices. * indicates that parameter is available for respective plant type.

Set U_a defines the range on the area of the power system from which the index is built. This is either *local* or *system*, meaning that the index is either built from the parameters of plant local to the fault, or from the whole system.

Set U_b describes the type of plant from which the index is built, either busbars, generation units, or network branches (lines and shunts).

U_c is a set of statistical functions used to reduce the values of an index over several items of plant to one single numerical value. Examples include *sum*, *average*, *rms* and *variance*. Up to twelve different functions are available.

U_d is the set of plant parameters used to form indices. Table 2 shows the parameters available for each type of plant.

U_e is a set of functions which describe how the index is derived from the power system measurements. This set contains three members, *change*, *ctp*, and *gradient*. *change* means that the index is found by taking the difference between the power system state at the start of the contingency and at the contingency termination point. *ctp* means that the index is given by the value of the power system state at the contingency termination point, and *gradient* means that the gradient of the power system state at the contingency termination point is used.

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